

SB

192

(FILE 1)

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE
1)</SUBJECT><COMM>SFIN27</COMM></TARGET>

Table of Contents

1. Fiscal Notes
2. CSSB 192(RES)
3. CSSB 192(RES) Sponsor Statement
4. CSSB 192(RES) Sectional Analysis
5. DOR's ACES Status Report: Galvin Letter to Gov Parnell (January 14, 2010)
6. DOR's ACES Status Report (January 14, 2010)
7. DOR's Oil and Gas Production Tax Status Report (January 18, 2011)
8. FAST Study (October, 2010)
9. Single Audit of the State of Alaska (Feb 28, 2011)
10. "State Tax Policy and Oil Production"
11. "Effectiveness of Severance Tax Incentives in the U.S. Oil Industry"
12. "State Taxation, Exploration, and Production in the U.S. Oil Industry"
13. Gas and Water Handling Constraints handout
14. North Slope of Alaska Facility Sharing Study

1.

Fiscal Notes

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB 192(RES)
Fiscal Note Number 1
(S) Publish Date 3/5/12

Identifier (file name) SB192-DNR-DOG-02-10-12 Dept. Affected Dept. of Natural Resources
Title OIL AND GAS PRODUCTION TAX RATES Appropriation Oil and Gas
Allocation Oil and Gas
Sponsor Senate Resources Committee
Requester Senate Resources Committee OMB Component Number 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	FY13	FY13	FY14	FY15	FY16	FY17	FY18
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)					
1002	Federal Receipts						
1003	GF Match						
1004	GF						
1005	GF/Prgm (DGF)						
1037	GF/MH (UGF)						
1178	temp code (UGF)						
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs 0.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

This is the initial fiscal note version for SB 192.

Prepared by William C. Barron, Director
Division Division of Oil and Gas
Approved by Daniel Sullivan, Commissioner
Department of Natural Resources

Phone 907-269-8800
Date/Time 02-10-12 12:00pm
Date 2/10/2012

FISCAL NOTE #1

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB 192(RES)

Analysis

SB 192 modifies the computation of the progressive element of the production tax rate to arrive at higher tax rates when production tax value per barrel of oil equivalent is higher than \$92.50. To understand the modification, a recap of the existing system is required.

"Production tax value" per barrel should not be confused with "price"; under the current production tax statute, production tax value is the netback value of oil less the operator's per barrel operating and capital costs. Currently, the tax rate under AS 43.55.011(e) starts at 25%; after production tax value per barrel exceeds \$30, the tax rate increases 0.4% for every additional dollar until production tax value per barrel reaches \$92.50. At that point the tax rate increase drops to 0.1% for each additional dollar. At \$92.50, the production tax rate is 50%. After 20% capital credits are applied, the effective tax rate drops. (If capital costs per barrel are assumed to be \$10 per barrel, then the effective tax rate would be around 48%.) The marginal tax rate, or the change in tax receipts divided by the change in profits, is around 86% when profits per barrel increase from \$91.50 to \$92.50. The high marginal tax rate is due to the increase in tax rate being applied against all the production tax value, not just the increment of profit generated by the one dollar increase in production tax value per barrel.

SB 192 amends AS 43.55.011(g) so that the tax rate continues to increase at 0.4% even when production tax value per barrel exceeds \$92.50. At higher profit per barrel levels, SB 192 would increase average and marginal tax rates. If production tax value per barrel reached \$110, the average production tax rate would be 57% rather than 51.75%. The marginal tax rate would be over 100% rather than 60%. For marginal tax rates exceeding 100%, a producer could increase after-tax profits by losing a dollar of before tax profits, either through incurring higher costs or forfeiting higher value.

All else equal, SB 192 will likely have an indeterminate negative impact on royalty revenue as it will make potential investments on the North Slope less attractive. Examining an investment in a project as a stand-alone venture (rather than an attempt to lower taxes due to the high marginal tax rates discussed above), SB 192 will lower the expected profitability of a project if a developer believes there is a possibility that during the project the production tax value per barrel will exceed \$92.50. If an investor believes that it is likely oil prices will be at current levels or higher in the future, then for a potential conventional small satellite development using representative cost and production profiles, a third or more of the expected net present value of a project might be lost due to the higher tax rate.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB 192(RES)
 Fiscal Note Number 2
 (S) Publish Date 3/5/12

Identifier (file name) SB192-DOR-TAX-02-09-12 Dept. Affected Revenue
 Title Oil and Gas Production Tax Rates Appropriation Taxation and Treasury
 Allocation Tax Division
 Sponsor Senate Resources Committee
 Requester (S) RES OMB Component Number 2476

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates				
OPERATING EXPENDITURES	FY13	FY13	FY14	FY15	FY16	FY17	FY18
Personal Services							
Travel							
Services							
Commodities							
Capital Outlay							
Grants, Benefits							
Miscellaneous							
TOTAL OPERATING	0.0	0.0	0.0	0.0	0.0	0.0	0.0

FUND SOURCE		(Thousands of Dollars)					
1002	Federal Receipts						
1003	GF Match						
1004	GF						
1005	GF/Prgm (DGF)						
1037	GF/MH (UGF)						
1178	temp code (UGF)						
TOTAL		0.0	0.0	0.0	0.0	0.0	0.0

POSITIONS							
Full-time							
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs _____ (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

Initial version.

Prepared by Cherie Nienhuis, Commercial Analyst
 Division Tax Division
 Approved by Bryan Butcher, Commissioner
Department of Revenue

Phone 907-269-1019
 Date/Time 2/9/2012; 1pm
 Date 2/9/2012

FISCAL NOTE #2

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB 192(RES)

Analysis

This bill makes a change to the progressive tax rate portion of the production tax at AS 43.55.011(g) by removing the second trigger of the progressive tax rate calculation that lowers the progressive tax rate to 0.1% on production tax values of \$92.50 and greater. The bill also removes the statutory maximum tax rate of 75% under the production tax statutes. The bill retains the initial trigger of \$30 in production tax value at which point the progressive tax rate is calculated as 0.4% per dollar increase in production tax value.

Given the Fall 2011 oil price, production, and lease expenditure forecast through FY 2017, the tax rate changes from this bill are not projected to have a direct revenue impact. The Fall 2011 forecast through the time period covered by this fiscal note (FY 2017) range from \$106 per barrel to close to \$110 per barrel for Alaska North Slope crude oil. Combined with anticipated production levels and lease expenditure projections, our forecast does not anticipate production tax values meeting or exceeding \$92.50 per barrel. Therefore, based on our most recent forecast, the progressivity rate changes in this bill will not impact revenue expectations.

If oil prices were to increase, or if production were to increase with no corresponding increase in lease expenditures, production tax rates, and therefore revenue, could be increased from this bill. With current production levels, and current transport costs and lease expenditure levels, much of North Slope crude oil would be subject to a production tax increase at \$120 - \$130 per barrel (ANS WC) and above. Without a maximum production tax rate, tax rates could continue to escalate until they exceed 100%. Marginal government take exceeds 100% at approximately \$140 per barrel, when holding all other assumptions constant. This means that at \$140 per barrel, the government would take more than 100% of every dollar that the oil price increases.

The bill has an effective date of January 1, 2013.

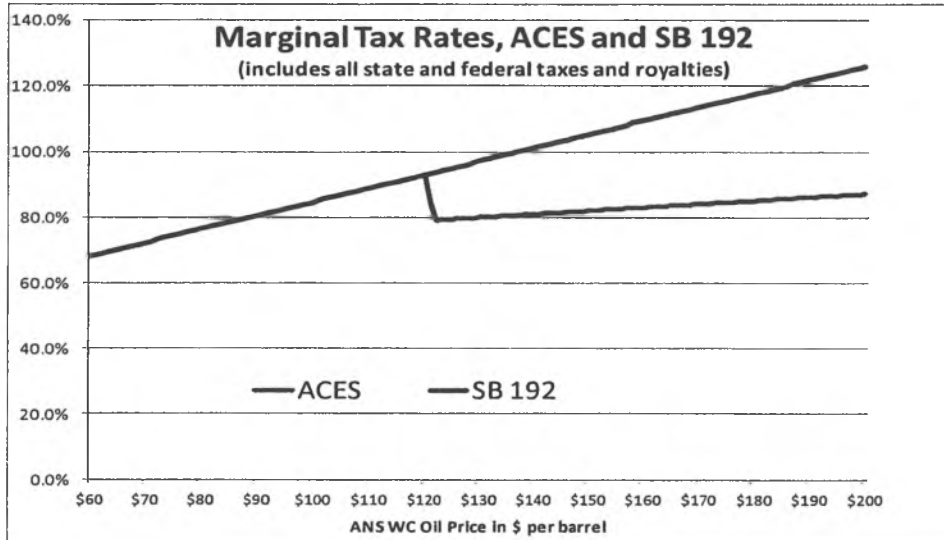
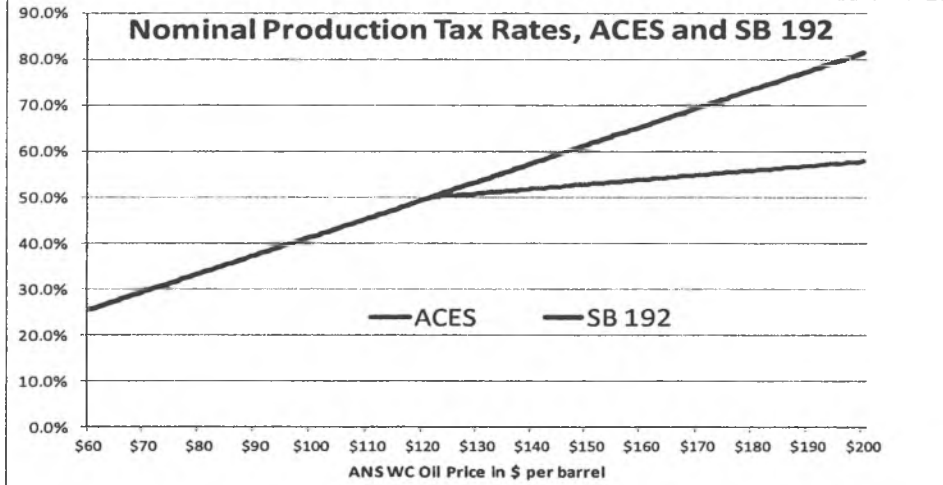
The following two graphs show nominal production tax rates and marginal tax rates at a range of oil prices given current transport and lease expenditure assumptions for ACES (current law) and SB 192. Nominal production tax rates are the ACES statutory production tax rates as calculated by taxpayers; marginal tax rates are the rates that the government collects of each additional dollar that the oil price increases. The marginal tax rate graph includes all major federal and state taxes and royalties.

FISCAL NOTE #2

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB 192(RES)

Analysis Continued



2.

CSSB 192 (RES)

CS FOR SENATE BILL NO. 192(RES)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE RESOURCES COMMITTEE

Offered: 3/5/12

Referred: Finance

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the oil and gas production tax; relating to the minimum tax on oil**
2 **and gas production; providing that the tax rate applicable to the production of oil as the**
3 **average production tax value of oil, gas produced in the Cook Inlet sedimentary basin,**
4 **and gas produced outside of the Cook Inlet sedimentary basin and used in the state**
5 **increases above \$30 shall be 0.35 percent multiplied by the number that represents the**
6 **difference between that average monthly production tax value and \$30, or the sum of 25**
7 **percent and the product of 0.1 percent multiplied by the number that represents the**
8 **difference between that average monthly production tax value and \$101.43, except that**
9 **the total rate determined in the calculation may not exceed 35 percent; providing for an**
10 **increase in the rate of tax on the production of gas as the average production tax value**
11 **on a BTU equivalent barrel basis of gas produced outside of the Cook Inlet sedimentary**
12 **basin and not used in the state increases above \$30; relating to payments of the oil and**

1 gas production tax; relating to the lease expenditures that may be deducted when
 2 determining production tax value; relating to the allocation of lease expenditures and
 3 adjustments to lease expenditures; relating to the availability of funds from the oil and
 4 gas production tax for appropriation to the community revenue sharing fund; providing
 5 for a reduction in production tax value for certain oil; relating to the duties of the
 6 Alaska Oil and Gas Conservation Commission; relating to a petroleum information
 7 management system; relating to the duties of the Department of Natural Resources, the
 8 Department of Revenue, and the Department of Labor and Workforce Development
 9 that relate to providing the Alaska Oil and Gas Conservation Commission with certain
 10 information relating to oil and gas; and providing for an effective date."

11 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

12 * **Section 1.** AS 29.60.850(b) is amended to read:

13 (b) Each fiscal year, the legislature may appropriate to the community revenue
 14 sharing fund an amount equal to the lesser of 20 percent of the money received by the
 15 state during the previous calendar year under both AS 43.55.011(g) and (p), or the
 16 difference between the amount of money received by the state during the
 17 previous calendar for oil and gas production subject to AS 43.55.011(f) and 25
 18 percent of the production tax value determined under AS 43.55.160 for oil and
 19 gas production subject to AS 43.55.011(f) produced during the previous calendar
 20 year, except the difference may not be less than zero. The amount appropriated
 21 may not exceed

22 (1) \$60,000,000; or

23 (2) the amount that, when added to the fund balance on June 30 of the
 24 previous fiscal year, equals \$180,000,000.

25 * **Sec. 2.** AS 31.05.030 is amended by adding a new subsection to read:

26 (n) The commission shall develop and maintain the petroleum information
 27 management system required under AS 31.05.031.

1 * **Sec. 3.** AS 31.05 is amended by adding a new section to read:

2 **Sec. 31.05.031. Petroleum information management system.** (a) The
3 commission shall develop and maintain an electronic petroleum information
4 management system to collect, secure, distribute, store, retrieve, and archive
5 information related to oil and gas exploration, development, and production in the
6 state. The purposes of the petroleum information management system are to improve
7 the administration of the oil and gas production tax and to facilitate exploration,
8 development, and production of oil and gas resources. The petroleum information
9 management system shall be accessible by the public.

10 (b) To the extent the information is available and is not confidential, the
11 petroleum information management system must include the following information:

- 12 (1) unit and joint operating agreements;
13 (2) state oil and gas exploration licenses and oil and gas leases;
14 (3) for exploration activities,
15 (A) exploration work programs and budgets;
16 (B) seismic data;
17 (C) drilling reports;
18 (D) logs;
19 (E) well tests;
20 (F) geological models and maps;
21 (4) for development activities,
22 (A) development plans with operating and capital expenditure
23 projections;
24 (B) construction progress reports;
25 (C) drilling reports;
26 (D) reservoir characterization;
27 (5) for production activities,
28 (A) production work programs and budgets;
29 (B) oil and gas sales, revenue, and pricing;
30 (C) transportation agreements;
31 (D) production data;

- 1 (E) injection data;
- 2 (F) operating and capital expenditures;
- 3 (G) facility maps and studies;
- 4 (6) for abandonment of oil and gas wells, leases, and production and
- 5 transportation facilities,
- 6 (A) abandonment plans and budgets;
- 7 (B) progress reports;
- 8 (7) for oil and gas related employment information,
- 9 (A) the number of resident and nonresident hires for each year;
- 10 (B) training opportunities; and
- 11 (8) other information the commission determines necessary and
- 12 relevant to the oil and gas production tax and to the exploration, development, and
- 13 production of oil and gas resources.

14 (c) The Department of Natural Resources, the Department of Revenue, and the
 15 Department of Labor and Workforce Development, in consultation with the
 16 commission, shall provide information described in (b) of this section that is not
 17 confidential and within each department's control to the commission for inclusion in
 18 the petroleum information management system. The information provided by a
 19 department under this subsection shall be in a form suitable for the commission to
 20 include in the petroleum information management system.

21 * **Sec. 4.** AS 31.05.093(c) is amended to read:

22 (c) The commission shall determine the regulatory cost charges levied under
 23 this section so that the total amount to be collected approximately equals the
 24 appropriations made for the operating costs of the commission under this chapter for
 25 the fiscal year. For the purpose of determining the regulatory costs charges under
 26 this subsection, the operating costs for the petroleum information management
 27 system (AS 31.05.031) may not be included in the operating costs of the
 28 commission.

29 * **Sec. 5.** AS 43.55.011(e) is amended to read:

30 (e) There is levied on the producer of oil or gas a tax for all oil and gas
 31 produced each calendar year from each lease or property in the state, less any oil and

1 gas the ownership or right to which is exempt from taxation or constitutes a
 2 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
 3 this section, the tax is equal to the sum of

4 (1) the annual production tax value of the taxable oil and gas as
 5 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

6 (2) the sum, over all months of the calendar year, of the tax amounts
 7 determined under

8 (A) subsection (g) of this section; and

9 (B) subsection (p) of this section.

10 * Sec. 6. AS 43.55.011(f) is repealed and reenacted to read:

11 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of
 12 this section, the provisions of this subsection apply to oil and gas produced from each
 13 lease or property within a unit or nonunitized reservoir that has cumulatively produced
 14 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent
 15 calendar year and from which the average daily oil and gas production from the unit or
 16 nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU
 17 equivalent barrels. Notwithstanding any contrary provision of law, a producer may not
 18 apply tax credits to reduce its total tax liability under (e) and (g) of this section for oil
 19 and gas produced from all leases or properties within the unit or nonunitized reservoir
 20 below 10 percent of the total gross value at the point of production of that oil and gas.
 21 If the amount of tax calculated by multiplying the tax rates in (e) and (g) of this
 22 section by the total production tax value of the oil and gas taxable under (e) and (g) of
 23 this section produced from all of the producer's leases or properties within the unit or
 24 nonunitized reservoir is less than 10 percent of the total gross value at the point of
 25 production of that oil and gas, the tax levied by (e) and (g) of this section for that oil
 26 and gas is equal to 10 percent of the total gross value at the point of production of that
 27 oil and gas.

28 * Sec. 7. AS 43.55.011(g) is amended to read:

29 (g) For each month of the calendar year for which the producer's average
 30 monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a
 31 [AS 43.55.160(a)(2) PER] BTU equivalent barrel of [THE] taxable oil and gas is more

than \$30, the amount of tax for purposes of (e)(2)(A) [(e)(2)] of this section is determined by multiplying the monthly production tax value of the taxable oil [AND GAS] produced during the month, gas produced during the month from a lease or property in the Cook Inlet sedimentary basin, and gas produced during the month from a lease or property outside the Cook Inlet sedimentary basin and used in the state by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of [THE] taxable oil and gas for the month is not more than \$101.43 [\$92.50], the tax rate is 0.35 [0.4] percent multiplied by the number that represents the difference between the producer's [THAT] average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of taxable oil and gas and \$30; [OR]

(2) if the producer's average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of [THE] taxable oil and gas for the month is more than \$101.43 [\$92.50], the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number that represents the difference between the producer's average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a [PER] BTU equivalent barrel of taxable oil and gas and \$101.43 [\$92.50], except that the sum determined under this paragraph may not exceed 35 [50] percent;

(3) for purposes of this subsection, the average monthly production tax value under AS 43.55.160(a)(2)(A) - (E) of a BTU equivalent barrel of taxable oil and gas is calculated by

(A) adding all of the monthly production tax values determined under AS 43.55.160(a)(2)(A) - (E); and

(B) dividing the sum calculated under (A) of this paragraph by the total amount, in BTU equivalent barrels, of

(i) taxable oil produced by the producer during the month;

(ii) taxable gas produced by the producer during the

month from a lease or property in the Cook Inlet sedimentary basin; and

(iii) taxable gas produced by the producer during the month from a lease or property outside the Cook Inlet sedimentary basin and used in the state.

* Sec. 8. AS 43.55.011 is amended by adding a new subsection to read:

(p) For each month of the calendar year for which the producer's average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas is more than \$30, the amount of tax on the production of gas for purposes of (e)(2)(B) of this section is determined by multiplying the monthly production tax value of the taxable gas produced during the month other than gas produced from a lease or property in the Cook Inlet sedimentary basin or gas produced outside the Cook Inlet sedimentary basin and used in the state by the tax rate calculated as follows:

(1) if the producer's average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the month is not more than \$101.43, the tax rate is 0.35 percent multiplied by the number that represents the difference between the producer's average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of gas and \$30;

(2) if the producer's average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas for the month is more than \$101.43, the tax rate is the sum of 25 percent and the product of 0.1 percent multiplied by the number that represents the difference between the producer's average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of gas and \$101.43, except that the sum determined under this paragraph may not exceed 35 percent;

(3) for purposes of this subsection, the average monthly production tax value under AS 43.55.160(a)(2)(F) and (G) of a BTU equivalent barrel of taxable gas is calculated by

(A) adding the monthly production tax value determined under AS 43.55.160(a)(2)(F) to the monthly production tax value determined under

AS 43.55.160(a)(2)(G); and

(B) dividing the sum calculated under (A) of this paragraph by the total amount, in BTU equivalent barrels, of the taxable gas produced by the producer during the month, other than gas produced from a lease or property in the Cook Inlet sedimentary basin or gas produced outside the Cook Inlet sedimentary basin and used in the state.

* **Sec. 9.** AS 43.55.020(a) is repealed and reenacted to read:

(a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i) and (p) shall pay the tax as follows:

(1) an installment payment of the estimated tax levied by AS 43.55.011(e), net of any tax credits applied as allowed by law, is due for each month of the calendar year on the last day of the following month; except as otherwise provided under (2) of this subsection, the amount of the installment payment is the sum of the following amounts in (A) - (C) of this paragraph, less 1/12 of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount of the installment payment may not be less than zero:

(A) the monthly production tax value for the month calculated under AS 43.55.160(a)(2)(B) multiplied by the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(g), added to the monthly production tax value for the month calculated under AS 43.55.160(a)(2)(G) multiplied by the sum of 25 percent and the tax rate calculated for the month under AS 43.55.011(p);

(B) the greater of

(i) 10 percent, under AS 43.55.011(f), of the gross value at the point of production of the oil and gas produced during the month from all leases or properties in the state that include land north of 68 degrees North latitude, other than oil and gas subject to AS 43.55.011(i) and gas subject to AS 43.55.011(o); or

(ii) the monthly production tax value for the month calculated under AS 43.55.160(a)(2)(A) multiplied by the sum of 25

1 percent and the tax rate calculated for the month under
 2 AS 43.55.011(g), added to the monthly production tax value for the
 3 month calculated under AS 43.55.160(a)(2)(F) multiplied by the sum of
 4 25 percent and the tax rate calculated for the month under
 5 AS 43.55.011(p); and

6 (C) for each lease or property, for gas subject to
 7 AS 43.55.011(j), oil subject to AS 43.55.011(k), and gas subject to
 8 AS 43.55.011(o), the monthly production tax value for the month calculated
 9 under AS 43.55.160(a)(2)(C), (D), or (E), as applicable, multiplied by the sum
 10 of 25 percent and the tax rate calculated for the month under AS 43.55.011(g);

11 (2) an amount calculated under (1)(C) of this subsection for oil or gas
 12 produced from a particular lease or property may not exceed the product obtained by
 13 carrying out the calculation set out in AS 43.55.011(j)(1) or (2) or 43.55.011(o), as
 14 applicable for gas, or set out in AS 43.55.011(k)(1) or (2), as applicable for oil, but
 15 substituting in AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the
 16 amount of taxable gas produced during the month for the amount of taxable gas
 17 produced during the calendar year and substituting in AS 43.55.011(k)(1)(A) or
 18 (2)(A), as applicable, the amount of taxable oil produced during the month for the
 19 amount of taxable oil produced during the calendar year;

20 (3) an installment payment of the estimated tax levied by
 21 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
 22 on the last day of the following month; the amount of the installment payment is the
 23 sum of

24 (A) the applicable tax rate for oil provided under
 25 AS 43.55.011(i), multiplied by the gross value at the point of production of the
 26 oil taxable under AS 43.55.011(i) and produced from the lease or property
 27 during the month; and

28 (B) the applicable tax rate for gas provided under
 29 AS 43.55.011(i), multiplied by the gross value at the point of production of the
 30 gas taxable under AS 43.55.011(i) and produced from the lease or property
 31 during the month;

(4) any amount of tax levied by AS 43.55.011(e) or (i), net of any credits applied as allowed by law, that exceeds the total of the amounts due as installment payments of estimated tax is due on March 31 of the year following the calendar year of production.

* **Sec. 10.** AS 43.55.020(d) is amended to read:

(d) In making settlement with the royalty owner for oil and gas that is taxable under AS 43.55.011, the producer may deduct the amount of the tax paid on taxable royalty oil and gas, or may deduct taxable royalty oil or gas equivalent in value at the time the tax becomes due to the amount of the tax paid. If the total deductions of installment payments of estimated tax for a calendar year exceed the actual tax for that calendar year, the producer shall, before April 1 of the following year, refund the excess to the royalty owner. Unless otherwise agreed between the producer and the royalty owner, the amount of the tax paid under AS 43.55.011(e) - (g) and (p) on taxable royalty oil and gas for a calendar year, other than oil and gas the ownership or right to which constitutes a landowner's royalty interest, is considered to be the gross value at the point of production of the taxable royalty oil and gas produced during the calendar year multiplied by a figure that is a quotient, in which

(1) the numerator is the producer's total tax liability under AS 43.55.011(e) - (g) and (p) for the calendar year of production; and

(2) the denominator is the total gross value at the point of production of the oil and gas taxable under AS 43.55.011(e) - (g) and (p) produced by the producer from all leases and properties in the state during the calendar year.

* **Sec. 11.** AS 43.55.160(a) is amended to read:

(a) Except as provided in (b) of this section and subject to an adjustment under AS 43.55.162, for the purposes of

(1) AS 43.55.011(e), the annual production tax value of the taxable

(A) oil [AND GAS] produced during a calendar year from leases or properties in the state that include land north of 68 degrees North latitude is the gross value at the point of production of the oil [AND GAS] taxable under AS 43.55.011(e) and produced by the producer from those leases or properties, less the producer's lease expenditures under AS 43.55.165 for the

1 calendar year applicable to the oil [AND GAS] produced by the producer from
2 those leases or properties, and the portion allocated under (g) of this section
3 of the producer's lease expenditures under AS 43.55.165 for the calendar
4 year incurred to explore land that is not a lease or property, or to explore
5 or develop a lease or property before commencement of commercial
6 production of oil or gas from the lease or property, if that land or any part
7 of the lease or property is located north of 68 degrees North latitude, as
8 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
9 TO GAS SUBJECT TO AS 43.55.011(o);]

10 (B) oil [AND GAS] produced during a calendar year from
11 leases or properties in the state outside the Cook Inlet sedimentary basin, no
12 part of which is north of 68 degrees North latitude, is the gross value at the
13 point of production of the oil [AND GAS] taxable under AS 43.55.011(e) and
14 produced by the producer from those leases or properties, less the producer's
15 lease expenditures under AS 43.55.165 for the calendar year applicable to the
16 oil [AND GAS] produced by the producer from those leases or properties, and
17 the portion allocated under (g) of this section of the producer's lease
18 expenditures under AS 43.55.165 for the calendar year incurred to explore
19 land that is not a lease or property, or to explore or develop a lease or
20 property before commencement of commercial production of oil or gas
21 from the lease or property, if that land or lease or property is located
22 outside the Cook Inlet sedimentary basin, and the land and all parts of the
23 lease or property are not north of 68 degrees North latitude, as adjusted
24 under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY TO
25 GAS SUBJECT TO AS 43.55.011(o);]

26 (C) oil produced during a calendar year from a lease or
27 property in the Cook Inlet sedimentary basin is the gross value at the point of
28 production of the oil taxable under AS 43.55.011(e) and produced by the
29 producer from that lease or property, less the producer's lease expenditures
30 under AS 43.55.165 for the calendar year applicable to the oil produced by the
31 producer from that lease or property, and the portion allocated under (g) of

1 this section of the producer's lease expenditures under AS 43.55.165 for
 2 the calendar year incurred to explore land that is not a lease or property,
 3 or to explore or develop a lease or property before commencement of
 4 commercial production of oil or gas from the lease or property, if that
 5 land or lease or property is located in the Cook Inlet sedimentary basin, as
 6 adjusted under AS 43.55.170;

7 (D) gas produced during a calendar year from a lease or
 8 property in the Cook Inlet sedimentary basin is the gross value at the point of
 9 production of the gas taxable under AS 43.55.011(e) and produced by the
 10 producer from that lease or property, less the producer's lease expenditures
 11 under AS 43.55.165 for the calendar year applicable to the gas produced by the
 12 producer from that lease or property, and the portion allocated under (g) of
 13 this section of the producer's lease expenditures under AS 43.55.165 for
 14 the calendar year incurred to explore land that is not a lease or property,
 15 or to explore or develop a lease or property before commencement of
 16 commercial production of oil or gas from the lease or property, if that
 17 land or lease or property is located in the Cook Inlet sedimentary basin, as
 18 adjusted under AS 43.55.170;

19 (E) gas produced during a calendar year from a lease or
 20 property in the state outside the Cook Inlet sedimentary basin and used in the
 21 state is the gross value at the point of production of that gas taxable under
 22 AS 43.55.011(e) and produced by the producer from that lease or property, less
 23 the producer's lease expenditures under AS 43.55.165 for the calendar year
 24 applicable to that gas produced by the producer from that lease or property,
 25 and the portion allocated under (g) of this section of the producer's lease
 26 expenditures under AS 43.55.165 for the calendar year incurred to explore
 27 land that is not a lease or property, or to explore or develop a lease or
 28 property before commencement of commercial production of oil or gas
 29 from the lease or property, if that land or lease or property is located
 30 outside the Cook Inlet sedimentary basin, as adjusted under AS 43.55.170;

31 (F) gas produced during a calendar year from leases or

1 properties in the state that include land north of 68 degrees North latitude
 2 is the gross value at the point of production of the gas taxable under
 3 AS 43.55.011(e) and produced by the producer from those leases or
 4 properties, less the producer's lease expenditures under AS 43.55.165 for
 5 the calendar year applicable to the gas produced by the producer from
 6 those leases or properties, and the portion allocated under (g) of this
 7 section of the producer's lease expenditures under AS 43.55.165 for the
 8 calendar year incurred to explore land that is not a lease or property, or
 9 to explore or develop a lease or property before commencement of
 10 commercial production of oil or gas from the lease or property, if that
 11 land or any part of the lease or property is located north of 68 degrees
 12 North latitude, as adjusted under AS 43.55.170; this subparagraph does
 13 not apply to gas subject to AS 43.55.011(o);

14 (G) gas produced during a calendar year from leases or
 15 properties in the state outside the Cook Inlet sedimentary basin, no part of
 16 which is north of 68 degrees North latitude, is the gross value at the point
 17 of production of the gas taxable under AS 43.55.011(e) and produced by
 18 the producer from those leases or properties, less the producer's lease
 19 expenditures under AS 43.55.165 for the calendar year applicable to the
 20 gas produced by the producer from those leases or properties, and the
 21 portion allocated under (g) of this section of the producer's lease
 22 expenditures under AS 43.55.165 for the calendar year incurred to explore
 23 land that is not a lease or property, or to explore or develop a lease or
 24 property before commencement of commercial production of oil or gas
 25 from the lease or property, if that land or lease or property is located
 26 outside the Cook Inlet sedimentary basin, and the land and all parts of the
 27 lease or property are not north of 68 degrees North latitude, as adjusted
 28 under AS 43.55.170; this subparagraph does not apply to gas subject to
 29 AS 43.55.011(o);

30 (2) AS 43.55.011(g) and (p), the monthly production tax value of the
 31 taxable

1 (A) oil [AND GAS] produced during a month from leases or
 2 properties in the state that include land north of 68 degrees North latitude is the
 3 gross value at the point of production of the oil [AND GAS] taxable under
 4 AS 43.55.011(e) and produced by the producer from those leases or properties,
 5 less 1/12 of the producer's lease expenditures under AS 43.55.165 for the
 6 calendar year applicable to the oil [AND GAS] produced by the producer from
 7 those leases or properties, and 1/12 of the portion allocated under (g) of this
 8 section of the producer's lease expenditures under AS 43.55.165 for the
 9 calendar year incurred to explore land that is not a lease or property, or
 10 to explore or develop a lease or property before commencement of
 11 commercial production of oil or gas from the lease or property, if that
 12 land or any part of the lease or property is located north of 68 degrees
 13 North latitude, as adjusted under AS 43.55.170; [THIS SUBPARAGRAPH
 14 DOES NOT APPLY TO GAS SUBJECT TO AS 43.55.011(o);]

15 (B) oil [AND GAS] produced during a month from leases or
 16 properties in the state outside the Cook Inlet sedimentary basin, no part of
 17 which is north of 68 degrees North latitude, is the gross value at the point of
 18 production of the oil [AND GAS] taxable under AS 43.55.011(e) and produced
 19 by the producer from those leases or properties, less 1/12 of the producer's
 20 lease expenditures under AS 43.55.165 for the calendar year applicable to the
 21 oil [AND GAS] produced by the producer from those leases or properties, and
 22 1/12 of the portion allocated under (g) of this section of the producer's
 23 lease expenditures under AS 43.55.165 for the calendar year incurred to
 24 explore land that is not a lease or property, or to explore or develop a
 25 lease or property before commencement of commercial production of oil
 26 or gas from the lease or property, if that land or lease or property is
 27 located outside the Cook Inlet sedimentary basin, and the land and all
 28 parts of the lease or property are not north of 68 degrees North latitude, as
 29 adjusted under AS 43.55.170; [THIS SUBPARAGRAPH DOES NOT APPLY
 30 TO GAS SUBJECT TO AS 43.55.011(o);]

31 (C) oil produced during a month from a lease or property in the

1 Cook Inlet sedimentary basin is the gross value at the point of production of
 2 the oil taxable under AS 43.55.011(e) and produced by the producer from that
 3 lease or property, less 1/12 of the producer's lease expenditures under
 4 AS 43.55.165 for the calendar year applicable to the oil produced by the
 5 producer from that lease or property, and 1/12 of the portion allocated under
 6 (g) of this section of the producer's lease expenditures under AS 43.55.165
 7 for the calendar year incurred to explore land that is not a lease or
 8 property, or to explore or develop a lease or property before
 9 commencement of commercial production of oil or gas from the lease or
 10 property, if that land or lease or property is located in the Cook Inlet
 11 sedimentary basin, as adjusted under AS 43.55.170;

12 (D) gas produced during a month from a lease or property in
 13 the Cook Inlet sedimentary basin is the gross value at the point of production
 14 of the gas taxable under AS 43.55.011(e) and produced by the producer from
 15 that lease or property, less 1/12 of the producer's lease expenditures under
 16 AS 43.55.165 for the calendar year applicable to the gas produced by the
 17 producer from that lease or property, and 1/12 of the portion allocated under
 18 (g) of this section of the producer's lease expenditures under AS 43.55.165
 19 for the calendar year incurred to explore land that is not a lease or
 20 property, or to explore or develop a lease or property before
 21 commencement of commercial production of oil or gas from the lease or
 22 property, if that land or lease or property is located in the Cook Inlet
 23 sedimentary basin, as adjusted under AS 43.55.170;

24 (E) gas produced during a month from a lease or property in
 25 the state outside the Cook Inlet sedimentary basin and used in the state is the
 26 gross value at the point of production of that gas taxable under
 27 AS 43.55.011(e) and produced by the producer from that lease or property, less
 28 1/12 of the producer's lease expenditures under AS 43.55.165 for the calendar
 29 year applicable to that gas produced by the producer from that lease or
 30 property, and 1/12 of the portion allocated under (g) of this section of the
 31 producer's lease expenditures under AS 43.55.165 for the calendar year

1 incurred to explore land that is not a lease or property, or to explore or
 2 develop a lease or property before commencement of commercial
 3 production of oil or gas from the lease or property, if that land or lease or
 4 property is located outside of the Cook Inlet sedimentary basin, as adjusted
 5 under AS 43.55.170;

6 (F) gas produced during a month from leases or properties
 7 in the state that include land north of 68 degrees North latitude is the
 8 gross value at the point of production of the gas taxable under
 9 AS 43.55.011(e) and produced by the producer from those leases or
 10 properties, less 1/12 of the producer's lease expenditures under
 11 AS 43.55.165 for the calendar year applicable to the gas produced by the
 12 producer from those leases or properties, and 1/12 of the portion allocated
 13 under (g) of this section of the producer's lease expenditures under
 14 AS 43.55.165 for the calendar year incurred to explore land that is not a
 15 lease or property, or to explore or develop a lease or property before
 16 commencement of commercial production of oil or gas from the lease or
 17 property, if that land or any part of the lease or property is located north
 18 of 68 degrees North latitude, as adjusted under AS 43.55.170; this
 19 subparagraph does not apply to gas subject to AS 43.55.011(o);

20 (G) gas produced during a month from leases or properties
 21 in the state outside the Cook Inlet sedimentary basin, no part of which is
 22 north of 68 degrees North latitude, is the gross value at the point of
 23 production of the gas taxable under AS 43.55.011(e) and produced by the
 24 producer from those leases or properties, less 1/12 of the producer's lease
 25 expenditures under AS 43.55.165 for the calendar year applicable to the
 26 gas produced by the producer from those leases or properties, and 1/12 of
 27 the portion allocated under (g) of this section of the producer's lease
 28 expenditures under AS 43.55.165 for the calendar year incurred to explore
 29 land that is not a lease or property, or to explore or develop a lease or
 30 property before commencement of commercial production of oil or gas
 31 from the lease or property, if that land or lease or property is located

outside the Cook Inlet sedimentary basin, and the land and all parts of the lease or property are not north of 68 degrees North latitude, as adjusted under AS 43.55.170; this subparagraph does not apply to gas subject to AS 43.55.011(o).

* **Sec. 12.** AS 43.55.160 is amended by adding new subsections to read:

(f) For purposes of (a) of this section, a lease expenditure is applicable to oil or gas produced from a lease or property, or to oil or gas produced from leases or properties in an area of the state, if the lease expenditure is

(1) a cost to explore, develop, or produce oil or gas from that lease or property, or to explore, develop, or produce oil or gas from one of those leases or properties in that area of the state, respectively; and

(2) incurred on or after the commencement of commercial production of oil or gas from the lease or property.

(g) For purposes of (a) of this section, a lease expenditure incurred during a calendar year to explore land that is not a lease or property, or to explore or develop a lease or property before commencement of commercial production of oil or gas from the lease or property, shall be allocated as provided in a regulation adopted by the department under AS 43.55.165(h) to and among oil, gas subject to AS 43.55.011(o), and gas not subject to AS 43.55.011(o) produced by the producer during that calendar year from leases or properties in the same area of the state as the land being explored or the lease or property being explored or developed, respectively.

(h) For purposes of (f) and (g) of this section, an area of the state is one of the following:

(1) land north of 68 degrees North latitude;

(2) land outside the Cook Inlet sedimentary basin not including any land north of 68 degrees North latitude; or

(3) the Cook Inlet sedimentary basin.

* **Sec. 13.** AS 43.55 is amended by adding a new section to read:

Sec. 43.55.162. Adjustment to production tax value for increasing oil production. (a) The production tax value of oil delivered to and transported by the Trans Alaska Pipeline System, as calculated under AS 43.55.160(a)(1)(A) and (B) and

1 AS 43.55.160(a)(2)(A) and (B), may be reduced by an amount determined by the
2 department under this section.

3 (b) A producer shall report to the department the total adjusted amount of
4 annual oil production and adjusted amount of the average daily statewide oil
5 production delivered by the producer for transport to the Trans Alaska Pipeline
6 System for both the calendar year immediately preceding the year for which the tax is
7 being determined and the year for which the tax is being determined. The report shall
8 be filed at the time the statement required under AS 43.55.030(a) is filed.

9 (c) When calculating the

10 (1) adjusted amount of the average daily statewide production under
11 (b) of this section, the producer shall exclude from the calculation the days on which
12 the rate of production is significantly reduced and the volume of production on those
13 days for which the rate of production is significantly reduced; for the purposes of this
14 paragraph, the rate of production is significantly reduced when the production of oil
15 delivered by the producer to the Trans Alaska Pipeline System for the day is less than
16 one-half of the average daily production for the year calculated by dividing the total
17 oil production that is produced by the producer and delivered to the Trans Alaska
18 Pipeline System for the year by the number of days in the year;

19 (2) adjusted amount of total annual oil production that is delivered by
20 the producer to the Trans Alaska Pipeline System, the producer shall multiply the
21 adjusted amount of average daily production determined under (1) of this subsection
22 by the number of days in the applicable calendar year; and

23 (3) adjusted amount of total annual oil production that is delivered by
24 the producer to the Trans Alaska Pipeline System for the year for which the tax is
25 being determined under (2) of this subsection, the producer may not include the
26 amount of production resulting from the purchase, merger, or other acquisition of
27 another producer and any production attributable to the producer from a unit in which
28 the producer did not participate in the calendar year immediately preceding the year
29 for which the tax is being determined; however, the increased production that may not
30 be included by a producer under this paragraph may be included in the adjusted
31 amount of total annual oil production for the year when determining the amount by

1 which production increases in the next succeeding year.

2 (d) After receiving a report by the producer under (b) of this section, the
3 department may reduce the production tax value determined under

4 (1) AS 43.55.160(a)(1)(A) and (B) by \$10 for each barrel of oil
5 delivered by the producer to the Trans Alaska Pipeline system during the year for
6 which the tax is being determined that exceeds the adjusted total annual production for
7 the calendar year immediately preceding the year for which the tax is being
8 determined; and

9 (2) AS 43.55.160(a)(2)(A) and (B) by \$10 for each barrel of oil
10 delivered to the Trans Alaska Pipeline System for each month in the year for which
11 the tax is being determined that exceeds 1/12 of the number of barrels by which the
12 adjusted total annual production for the year for which the tax is being determined
13 exceeds the adjusted total annual production for the calendar year immediately
14 preceding the year for which the tax is being determined.

15 (e) The department shall notify the producer of the amount of tax reduction
16 allowed as a result of a reduction in production tax value determined by the
17 department under (d) of this section. At the request of the producer, the department
18 may refund any amount due to the producer as a result of the reduction in production
19 tax value or credit the amount of the tax reduction against the liability of the taxpayer
20 for a tax due under this title.

21 (f) A tax reduction that results from a reduction in the production tax value
22 under this section may not be considered when a producer is required to calculate and
23 pay any amount due under AS 43.55.020(a). However, at the request of the producer, a
24 credit allowed under (e) of this section may be applied against a payment due under
25 AS 43.55.020(a) for a period after the department determines the amount of reduction
26 in the production tax value.

27 (g) When determining the average monthly production tax value in
28 AS 43.55.011(g), the average monthly production tax value shall be determined before
29 applying any adjustment under (d) of this section.

30 (h) The department may adopt regulations specifying the information that
31 must be included in the report filed by a producer under (b) of this section and other

1 regulations necessary for the administration of this section.

2 * **Sec. 14.** AS 43.55.165(h) is amended to read:

3 (h) The department shall adopt regulations that provide for reasonable
4 methods of allocating costs between oil and gas, between gas subject to
5 AS 43.55.011(o) and other gas, and between leases or properties in those
6 circumstances where an allocation of costs is required to determine lease expenditures
7 that are costs of exploring for, developing, or producing oil deposits or costs of
8 exploring for, developing, or producing gas deposits, or that are costs of exploring for,
9 developing, or producing oil or gas deposits located within different leases or
10 properties. When adopting a regulation for determining a reasonable method of
11 allocating lease expenditures between the production of oil and the production of
12 gas, the department shall, to the extent possible, provide for the allocation of
13 lease expenditures in proportion to the gross value at the point of production for
14 oil produced and gas produced.

15 * **Sec. 15.** AS 43.55.170 is amended by adding a new subsection to read:

16 (d) The department shall adopt regulations that provide for reasonable
17 methods of allocating the adjustments to a producer's lease expenditures in (a) of this
18 section and the payments and credits described in (b) of this section between oil and
19 gas, between gas subject to AS 43.55.011(o) and other gas, and between leases or
20 properties in those circumstances where an allocation of costs is required to determine
21 lease expenditures that are costs of exploring for, developing, or producing oil
22 deposits, or costs of exploring for, developing, or producing gas deposits, or that are
23 costs of exploring for, developing, or producing oil or gas deposits located within
24 different leases or properties. When determining a reasonable method of allocating the
25 adjustments to a producer's lease expenditures between the production of oil and the
26 production of gas, the department shall consider allocating the adjustments in
27 proportion to the lease expenditures allocated to the production of oil and the
28 production of gas under regulations adopted by the department under
29 AS 43.55.165(h).

30 * **Sec. 16.** The uncodified law of the State of Alaska is amended by adding a new section to
31 read:

1 IMPLEMENTATION OF THE PETROLEUM INFORMATION MANAGEMENT
2 SYSTEM; RECOMMENDATION FOR STATUTORY CHANGES. The Alaska Oil and Gas
3 Conservation Commission shall develop and implement a work plan for the development of
4 the petroleum information management system required by AS 31.05.031, enacted by sec. 3
5 of this Act, so that the system is operational before January 1, 2014.

6 * **Sec. 17.** The uncodified law of the State of Alaska is amended by adding a new section to
7 read:

8 APPLICABILITY. The reduction in production tax value under AS 43.55.162,
9 enacted by sec. 13 of this Act, applies to qualifying oil produced after December 31, 2012. In
10 this section, "qualifying oil" means oil delivered to the Trans Alaska Pipeline System the
11 production tax value of which is calculated under AS 43.55.160(a)(1)(A) and (B) and
12 43.55.160(a)(2)(A) and (B).

13 * **Sec. 18.** This Act takes effect January 1, 2013.

3.

CSSB 192 (RES)

**Sponsor
Statement**

Sponsor Statement CSSB 192, Version E

Committee Substitute for Senate Bill 192 contains five significant additions to Alaska's oil and gas production tax statutes, to include the following:

- Lowers the Rate of Progressivity and the Cap on Progressivity
- Rewards Increased Production
- Establishes a Gross Minimum Tax
- Separates oil and natural gas for purposes of calculating the progressivity portion of the production tax (aka decoupling)
- Creates an Oil Information System

Lowers Progressivity

CSSB 192 lowers both the rate of progressivity and the cap on progressivity.

The legislation retains the original trigger of \$30 in Production Tax Value (PTV), at which point the progressive tax rate is calculated at .35% per dollar increase in PTV up to 50% (\$101.43). This is a reduction from the current progressivity rate of .4% to .35%.

At 50% Production Tax Value (i.e., \$101.43), CSSB 192 adds a second trigger on the progressive tax rate calculation that lowers the progressive tax rate to .1% on PTV up to 60% (\$201.43).

CSSB 192 adds a statutory maximum tax rate of 60% under the production tax statutes. This is a reduction in the maximum tax rate from 75%, as it is currently in ACES, to 60%.

The goal is to return the "upside potential" to industry at high oil prices.

Rewards Increased Production

The purpose of this provision is to reward companies that increase their North Slope production levels from one year to the next, helping to increase TAPS throughput. Companies which achieve this goal will earn an allowance on the oil they produce above the prior year.

The allowance reduces their Production Tax Value (or PTV) by \$10 for the new barrels of oil produced. This allowance should not be confused with a tax credit or a lowering of tax rates. It is a reduction in the PTV used to calculate production tax.

Again, this allowance wouldn't influence the tax rate itself. It would not count as a lease expenditure and isn't part of the calculation that determines average profits per barrel.

Establishes a Gross Minimum Tax

This provision of the legislation will establish a production tax floor of 10% of the gross value of oil at the point of production for legacy fields in Alaska. The floor would apply only to fields which have already produced a billion barrels of oil and are still producing 100,000 barrels a day on average.

Prudhoe Bay and Kuparuk are the only fields that currently meet this definition.

ACES currently has a production tax floor. It is between 0-4%, depending on the price of oil, and can be brought even lower by credits. This means the state could actually owe companies production tax in a low price environment, when the state has a cash flow deficit and is struggling to pay for the most essential state services.

This provision is intended to alleviate concerns that the current floor does not adequately protect the state when oil prices are low. In fact, at prices as low as \$70, the state may take in more with a 10% gross floor than it would with ACES.

This provision protects the state at low oil prices.

Decoupling

This provision separates oil and natural gas for purposes of calculating the progressivity portion of the production tax. Under this bill, the progressivity surcharges for oil and Cook Inlet and in-state gas would be calculated together, but distinctly from export gas, instead of the current practice on all oil and gas combined. The progressivity structure itself would be changed to conform with the rates set forth in this legislation.

Under current law, the tax rate is based on the combined BTU value of oil and gas. However, oil and gas can, and do, have vastly different values on a BTU basis. Currently, a BTU of oil is worth much more than a BTU of gas. Accordingly, once a major gas sale starts, overlaying the existing oil production, the BTU value of the combined oil and gas would be much lower than it was for oil alone. This has been referred to as the "dilution effect" and could cause a significant reduction in oil taxes as a result of a major gas sale. The existing tax structure, in conjunction with the inherent uncertainty of future oil and gas prices, exposes the state to significant financial risk were a major gas sale to occur. The structure also creates economic instability for entities looking to participate in the development and financing of a natural gas pipeline project in Alaska.

This legislation removes the dilution effect by having progressivity calculated distinctly for oil and gas. This will result in no reduction in oil taxes from a major gas sale.

As in current law, the bill gives the Department of Revenue the authority to adopt regulations to allocate costs between oil and gas, with the added instruction that a method based on relative BTU barrel of oil equivalents should be considered.

Oil Information System

Concerns have been raised about oil and gas information that is not available to legislative policy-makers and the public. While much of the information is confidential under law, there is a considerable amount that is public, but it is scattered among several agencies and can, at times, be difficult to find.

This provision in law will begin the process of making information more available to the policy-makers, public, and oil and gas companies who may be seeking to do business in Alaska's oil fields.

This provision of the legislation will require the Alaska Oil and Gas Commission (AOGCC) to develop an electronic Petroleum Information Management System that will contain public information currently gathered by the commission, as well as the Departments of Revenue, Natural Resources and Labor & Workforce Development.

The system will consolidate available, public oil and gas information that is currently scattered among several agencies for the purpose of the system improving the administration of the oil and gas production tax and to facilitate exploration, development, and production of oil and gas resources.

The information list that is in the legislation is taken from a 2007 Gaffney Cline report that provided an overview of how the acquisition, distribution and publication of oil company data is handled in other oil and gas producing regimes.

The legislation directs the departments that have control over the various aspects of the information to provide what is not confidential to the commission in a form suitable for distribution.

The legislation directs AOGCC to develop and implement the system.

The bill has an effective date of January 1, 2013.

4.

**CSSB 192 (RES)
Sectional
Analysis**

LEGAL SERVICES

DIVISION OF LEGAL AND RESEARCH SERVICES
LEGISLATIVE AFFAIRS AGENCY
STATE OF ALASKA

(907) 465-3867 or 465-2450
FAX (907) 465-2029
Mail Stop 3101

State Capitol
Juneau, Alaska 99801-1182
Deliveries to: 129 6th St., Rm. 329

MEMORANDUM

March 9, 2012

SUBJECT: Sectional summary for CSSB 192(RES), relating to the oil and gas production tax (Work Order No. 27-LS1305\E)

TO: Senator Joe Paskvan
Co-Chair of the Senate Resources Committee
Attn: Jeff Stepp

FROM: Donald M. Bullock Jr. *KGB*
Legislative Counsel

You have requested a sectional summary of the above-described bill.

As a preliminary matter, note that a sectional summary of a bill should not be considered an authoritative interpretation of the bill and the bill itself is the best statement of its contents. If you would like an interpretation of the bill as it may apply to a particular set of circumstances, please advise.

Section 1. Amends AS 29.60.850(b) to conform to the decoupling of certain gas production from oil production¹ for tax purposes and the repeal and reenactment of the minimum tax on certain oil and gas production.

Section 2. Amends AS 31.05.030 by adding a new subsection that requires the Alaska Oil and Gas Conservation Commission (AOGCC) to develop and maintain the petroleum information management system.

Section 3. Adds AS 31.05.031 to AS 31.05 to provide for the development and maintenance of the petroleum information management system. Describes the information to be included and requires the Department of Natural Resources, the Department of Revenue, and the Department of Labor and Workforce Development to work with AOGCC to include relevant information from each department in the

¹ Under the decoupling of oil and gas production in the bill, the progressive part of the tax rate is split so that the production of oil, gas in the Cook Inlet sedimentary basin, and gas produced outside of Cook Inlet and used in the state is subject to one set of rates, and all other gas production is subject to a different set of rates. See the amendments to AS 43.55.011(e) in sec. 5, AS 43.55.011(g) in sec. 7, and new subsection AS 43.55.011(g) in sec. 8 of the bill.

petroleum information management system. Provides that the petroleum information management system shall be accessible by the public.

Section 4. Amends AS 31.05.093(c) to exclude the operating costs for the petroleum information management system from the operating costs of AOGCC for the purpose of determining regulatory cost charges.

Section 5. Amends AS 43.55.011(e) to conform to the decoupling of the progressive part of the production tax on oil, gas produced in the Cook Inlet sedimentary basin, and gas produced outside of Cook Inlet and used in the state, from the progressive part of the production tax applicable to other gas.

Section 6. Repeals and reenacts AS 43.55.011(f) to set a minimum tax of 10 percent of the gross value at the point of production for certain areas with historical production of 1,000,000,000 BTU equivalent barrels of oil or gas and average daily oil and gas production for the most recent calendar year of more than 100,000 BTU equivalent barrels.

Section 7. Amends AS 43.55.011(g) to limit the application of the progressive tax under the subsection to oil, gas produced in the Cook Inlet sedimentary basin, and gas produced outside of the Cook Inlet sedimentary basin and used in the state. This section also changes the first level of the progressive tax to apply to an average production tax of not more \$101.43 and lowers the tax rate for the first level to 0.35 percent for each dollar of average production tax value above \$30. The second level is amended to apply to average production tax value of \$101.43 or more and sets the maximum tax rate for the second level to 35 percent, a reduction from 50 percent.

Section 8. Adds a new subsection to AS 43.55.011 with the same tax rates in AS 43.55.011(g), but provides that those tax rates apply to gas not subject to tax under AS 43.55.011(g).

Section 9. Repeals and reenacts AS 43.55.020(a) to conform to AS 43.55.011(f) as repealed and reenacted in sec. 6 of the bill, the amendment to AS 43.55.011(g) in sec. 7 of the bill, and AS 43.55.011(p) in sec. 8 of the bill.

Section 10. Amends AS 43.55.020(d) to conform to the amendment to AS 43.55.011(g) in sec. 7 of the bill, and AS 43.55.011(p) in sec. 8 of the bill.

Section 11. Amends AS 43.55.160(a) by making the determination of annual and monthly production tax values subject to AS 43.55.162, a new section added by sec. 12 of the bill. Conforms the determination of production tax values to the amendment to AS 43.55.011(g) in sec. 7 of the bill, and AS 43.55.011(p) in sec. 8 of the bill.

Section 12. Amends AS 43.55.160 by adding three subsections to describe the allocation of lease expenditures to oil or gas production or exploration in different areas in the state.

Section 13. Adds a new section to AS 43.55 -- AS 43.55.162 -- that offers a producer a \$10 a barrel reduction in production tax value for each barrel of oil delivered to the Trans Alaska Pipeline System that is above the base volume that is determined for the previous calendar year. The section also provides that the average monthly production tax value used for determining the tax rate under AS 43.55.011(g) shall be calculated before applying the reduction on production tax value allowed for increased production.

Section 14. Amends AS 43.55.165(h) to require the Department of Revenue to allocate lease expenditures between oil and gas production based on the gross value at the point of production of the oil and gas.

Section 15. Adds a new subsection to AS 43.55.170 that requires the Department of Revenue to adopt regulations that provide for reasonable methods of allocating adjustments to lease expenditures, payments, and credits between different categories of oil and gas production and between leases and properties.

Section 16. Adds a new section to uncodified law to require AOGCC to develop and implement a work plan for the development of the petroleum management system so that the system is operational before 2014.

Section 17. Adds a new section to uncodified law that states that the reduction in production tax value under AS 43.55.162 in sec. 13 of the bill applies to qualifying oil produced after December 31, 2012.

Section 18. Provides a January 1, 2013 effective date.

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5.

DOR' s ACES
Status Report:
Galvin Letter to
Gov. Parnell
Jan. 14, 2010

State of Alaska

Department of Revenue
Commissioner's Office



SEAN PARNELL, GOVERNOR

333 Willoughby Avenue, 11th Floor

P.O. Box 110400

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Phone: (907) 465-2300

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January 14, 2010

Honorable Governor Parnell,

Recently you requested a review of Alaska's oil and gas production tax, and recommendations for how the production tax could be improved. Enclosed for your review is analysis of Alaska's oil and gas production tax (otherwise referred to as "ACES"), which was compiled at my request by the Department of Revenue's technical staff. The ACES Status Report evaluates whether ACES is meeting its intended goals of providing a fair share of revenue to the state while encouraging investment in new oil and gas exploration and development activities.

Based on the report, I am recommending a collection of potential amendments to ACES and its associated Exploration Incentive Credit (EIC) program. The amendments are primarily intended to accomplish two things: 1. Further incentivize drilling and other production enhancing activities; and 2. Address a number of provisions of ACES that may keep explorers from enjoying the full intended value of the capital credit program.

The status report shows that ACES successfully allowed the state to share in the benefits of high oil prices while accommodating fluctuations in production costs and oil prices. ACES adjusted when oil prices tumbled and kept oil operations in Alaska highly profitable relative to other oil provinces. With respect to the impact that the new production tax has had on investment activity, the report is positive, but ultimately inconclusive. While the overall level of taxation increased with ACES, it distributed the impact of that tax burden in a way designed to incentivize investment in new exploration and development. Since ACES passed the legislature, overall spending on oil and gas activities on the North Slope has increased. However, given only two and a half years of experience, during which time oil prices climbed to \$140 per barrel then plunged to under \$30 per barrel, it would be premature to attribute the increased level of oil company investment to the success of ACES.

Oil taxes are clearly an important factor in industry investment decisions. However, it is misleading to isolate their influence from other key factors, such as world oil prices, geologic potential, access to land, resources and markets, costs of infrastructure and support services, and the legal and regulatory framework. As noted in the report, the true merit of Alaska's current fiscal system can only be determined when it is evaluated in conjunction with these other variables. The scope of the status report, and the limited timeframe since ACES passed, do not allow for such a comprehensive analysis and definitive conclusions.

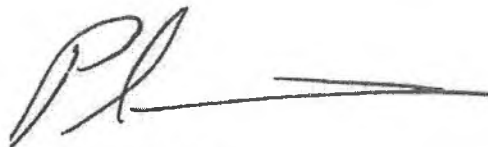
In addition to documenting several promising trends in industry spending activity, the report notes a number of discrete policy issues associated with the production tax where improvement can be made. These warrant your consideration as potential amendments to the ACES framework.

1. **Increase Credits for All Well-Related Activity to 30%:** The Capital Credit and Exploration Incentive Credit (EIC) programs have been identified as influential in spurring exploration activities. However, the EIC program's 30% credits are only available to wells located more than 3 miles from all existing wells. The state has a significant interest in also incentivizing infill drilling and other well work that will increase oil production, particularly for heavy oil. I therefore recommend expanding the EIC program so that all expenditures related to drilling and well work that add new production or increase the efficiency of existing production will qualify for the 30% EIC credit under AS 43.55.025 regardless of a well's location relative to existing wells.
2. **Increase Access to Capital Credits for New Explorers:** Small producers are currently required to invest in new activities during subsequent years in order to obtain direct payment from the state for previously earned tax credits. This is not an issue for existing producers because they simply deduct credits from their current tax bill and do not need to seek direct payment from the state. Deleting this provision would make the tax credits more accessible to smaller explorers, level the playing field between new and existing operators, and eliminate an unfair double standard.
3. **Accelerate Capital Credit Usage:** Companies currently can only use half of their capital credits in the year they are earned, and the other half the following year. This is true whether the credits are applied against a tax liability or purchased by the state. Taxpayers would see increased value in the credits if they could apply the entire credit in the first year. In addition, this would ease the cost of administering these credits.

4. **Waive Interest on Late Tax Payments Due to Drafting of Regulations:** The ACES regulations, including those defining 'allowable lease expenditures' are being finalized this month. Under the statutes, these regulations are to be applied retroactively to various dates in 2007. To the extent additional taxes are due as a result of the application of the new regulations, such payments would be subject to interest and possibly penalties. While the department can waive penalties, it cannot waive interest charges. A statutory change is required in order to permit the waiver of interest.

I am confident you will find the ACES Status Report informative and interesting. Please consider my recommendations to improve the effectiveness and fair administration of ACES and the EIC program. I look forward to continuing to work with you to encourage additional oil and gas development while preserving Alaska's equitable share of oil and gas profits.

Sincerely,

A handwritten signature in black ink, appearing to be 'P. Galvin', followed by a long horizontal line extending to the right.

Patrick S. Galvin
Commissioner

6.

**DOR' s ACES
Status Report:
Jan. 14, 2010**

Alaska's Clear and Equitable Share (ACES)
Status Report
Alaska Department of Revenue
January 14, 2010

Introduction

In November 2007, the Alaska Legislature passed House Bill 2001, known as Alaska's Clear and Equitable Share (ACES). ACES made modifications to the prior production tax called the Petroleum Profits Tax (PPT), enacted in 2006. The changes made first with PPT and later with ACES represented substantial production tax reform in that the basis of the tax shifted from the *gross value* to the *net value* of oil and gas production. The gross tax which had been in place prior to the PPT is generally referred to as the Economic Limit Factor (ELF).

This report was prepared at the request of the Commissioner of Revenue in order to evaluate whether ACES is meeting its intended goals of providing a fair share of oil and gas revenue to the state, and encouraging investment in the exploration and development of new oil and gas resources in Alaska.

Following are the key findings of this report:

- 1) State revenues under ACES in FY 2009 exceeded amounts which would have been generated under either the PPT or ELF systems. The crossover point at which ACES is projected to provide more revenue than ELF is \$51 per barrel west coast price in FY 2010.
- 2) Activation of the progressive surcharge is estimated to occur when west coast sales prices reach \$56 per barrel.
- 3) Capital spending on the North Slope totaled over \$2.2 billion in FY 2009 an increase over FY 2008. This is nearly the highest level of capital spending in nominal dollars since oil production began in the state.
- 4) The impact of the production tax modifications on industry investment cannot be clearly determined due to the influence of other factors and given the limited timeframe during which ACES has been in place.

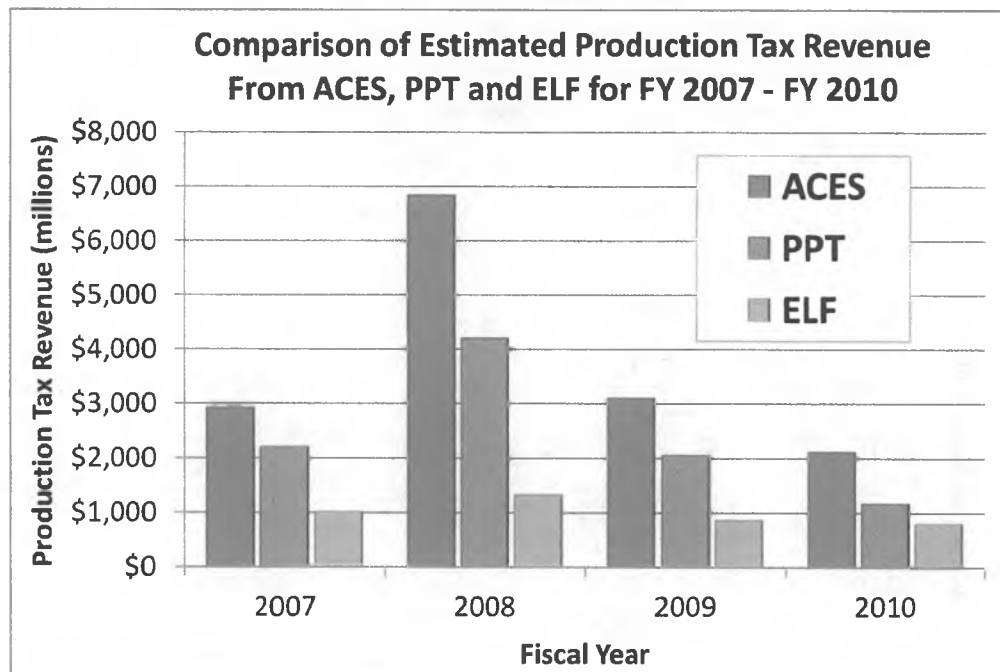
- 5) Operating costs have risen since the enactment of PPT and ACES, but the impact of these cost increases to state tax revenues was moderated by the “standard deduction” provision of ACES, which expired December 31, 2009.
- 6) Increased reporting requirements, particularly of forward looking expenditure information, has greatly enhanced the accuracy of the Department’s revenue forecasting efforts.
- 7) The Department has made significant progress in implementing ACES regulations, but there will be challenges to both the department and taxpayers as the regulations are implemented. Preliminary audits of taxpayers under the new profits-based system (formerly PPT) have begun, consistent with the normal audit timeframe.

Comparison of Revenues under ACES, PPT and ELF

The net tax structure – first enacted under PPT (2006) and later with ACES (2007) – represents a significant change from the oil and gas tax structure used for much of Alaska’s history. Under the earlier tax, known as the Economic Limit Factor (ELF), production tax was levied on oil and gas producing properties, regardless of whether operations were profitable. The current production tax structure requires companies to pay tax only when they are making profits from oil and gas production in the state. In addition, tax credits are provided for capital expenditures, with higher credits available for certain oil and gas exploration investments.

Since its enactment in 2007, ACES has generated more state revenue than would have been generated under either PPT or ELF. In FY 2008, a period of very high oil prices and profits, ACES generated \$6.8 billion in production tax revenue, compared with \$4.2 billion which would have been received under PPT and \$1.3 billion which would have been received under ELF. In fiscal year 2009, during which west coast oil prices average \$68.34, ACES generated just over \$3.1 billion. This compares with roughly \$2 billion that would have been generated under PPT and \$858 million under the earlier ELF system.

Figure A compares revenue from ACES, PPT and ELF for FY 2007-2010. The FY 2009 revenues are preliminary. Estimates for FY 2010 are based on the Department’s fall 2009 forecast of an average west coast oil price of \$66.93 per barrel.

Figure A¹

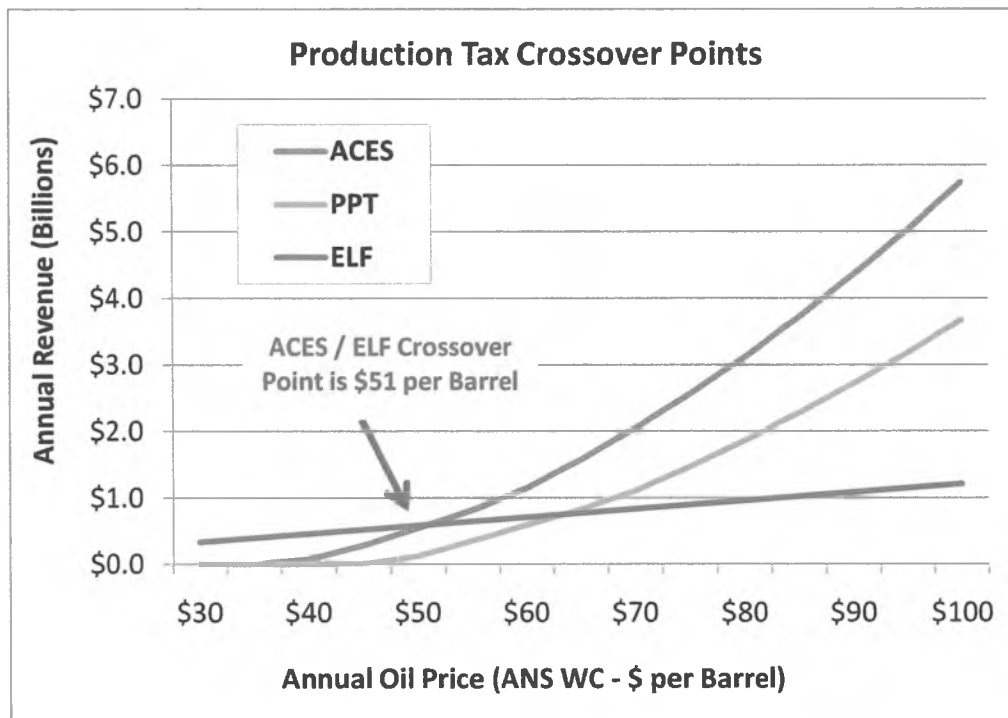
The progressive feature in ACES means that the state receives more production tax revenue when oil prices are high relative to underlying costs. Similarly, it significantly lessens the state's share of revenues when per-barrel margins decline. This effect was illustrated in 2008, when oil prices reached a high of \$140 per barrel in July, bringing in \$900 million in production tax for the month, and later plunged to below \$30 per barrel in December, producing a total of \$50 million in production tax for the month. Over the course of the full year, ANS crude oil averaged over \$92 per barrel, resulting in five times more revenue than would have been realized under the ELF system.

Figure B shows estimated revenues that would be received under ACES, ELF and PPT at various oil prices.² The oil price crossover point at which the state receives more revenue under ACES than the ELF system is roughly \$51 per barrel. The crossover point has increased over prior

¹ Production tax revenue includes surcharges but does not include any settlements which go to the Constitutional Budget Reserve Fund. FY 2007 PPT revenue includes true-up payments for the period of April 2006 through December 2006. FY 2007 ACES revenue assumes similar true-up payments for comparison purposes. For FY 2007 - FY 2009, assumes actual data for oil price, production, costs and other variables. For FY 2010, assumes oil price, production, costs and other variables as of the fall 2009 forecast. Costs under PPT for FY 2010 for Prudhoe Bay and Kuparuk are based on aggregated company forecasts. For ACES only, assumes that standard deduction would apply for all of FY 2007-FY 2009 and first half of FY 2010. Actual tax revenue, as opposed to modeled revenue, is used for PPT in FY 2007 and ACES in FY 2008-FY 2009.

² This analysis assumes a constant oil price for the entire year, production of 655,000 barrels per day, deductible lease expenditures of \$20 per barrel and transit costs of \$6 per barrel.

years because lease expenditures, which are deductible under ACES, have increased since ACES was passed. It is expected that lease expenditures will decrease as costs decline in delayed response to the decline in oil prices from their 2008 levels.

Figure B³

Lease Expenditures

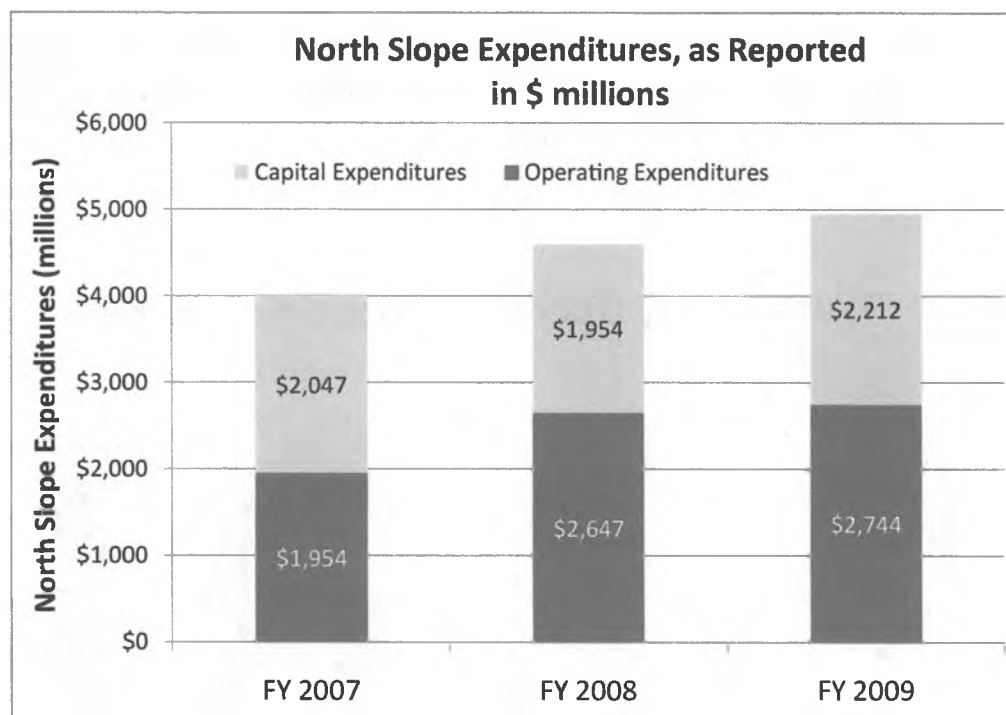
With the introduction of the net tax, it became necessary for the state to identify and forecast allowable lease expenditures for purposes of the tax calculation. Prior to the passage of PPT, the department had not been required to track or audit oil and gas production costs in Alaska. Some early cost data had been acquired directly from producing companies and through preliminary examination of federal tax returns. However, even during the debate over PPT, the state did not have access to comprehensive, Alaska-specific data that would enable policymakers to analyze the effects of the proposed tax over the life of a project. With much more information now being provided under the new tax structure, the department is developing a better understanding of oil and gas costs in Alaska, which will significantly benefit future policy deliberations.

³ Assumes fixed operating and capital cost of \$20 per barrel.

Lease expenditures fall into two general categories that constitute the major deductions under the ACES tax system. Operating expenditures are the costs to operate an oil or gas production facility on a day-to-day basis. These include labor, heat and light for the facilities, and some well work and minor equipment repairs. Capital expenditures are costs incurred to enhance or improve the reserve base, level of production, or facilities. Drilling is one of the most common forms of capital costs, as is facility construction or expansion.

Figure C shows the operating and capital expenditures, as reported on company tax returns and monthly reports, for their North Slope operations, from FY 2007 through FY 2009. Note that the graph represents all reported expenditures for all North Slope properties, regardless of whether or not they are subject to the “standard deduction” provisions of AS 43.55.165(j).

Figure C⁴



Operating Expenditures

Operating costs have risen significantly in recent years for the oil and gas industry worldwide. This has often been linked to the corresponding rise in oil prices beginning around 2002. Projects around the world that were once marginally economic have become viable, increasing the demand for limited supplies of engineering, procurement and construction services, as well

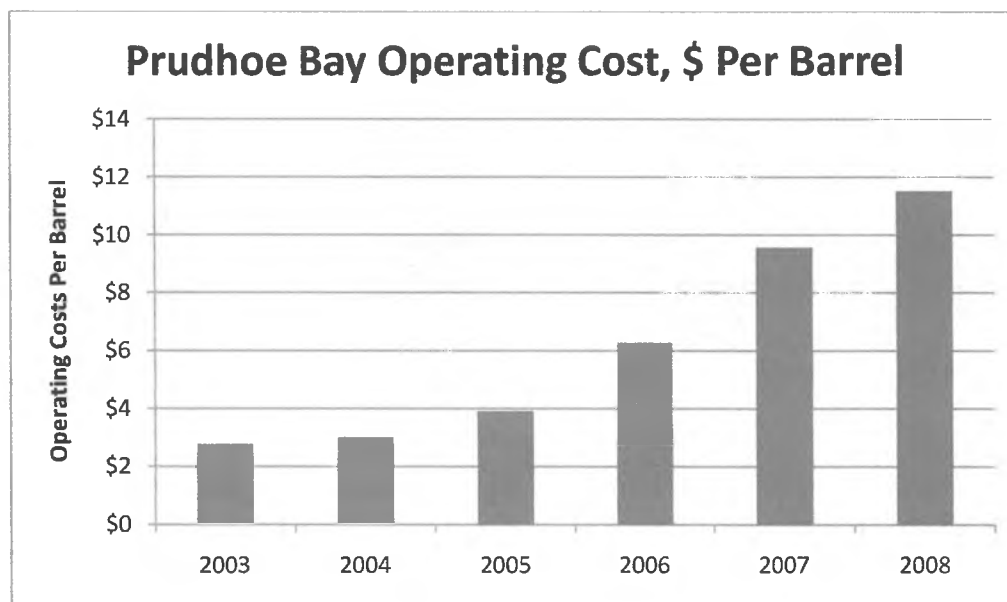
⁴ Operating expenditures includes total reported costs, not standard deduction; FY 2007 estimated based on incomplete reporting

as raw materials. Cambridge Energy Research Associates (CERA) reports the upstream operating cost index rose for oil and gas field operations roughly 67% between 2002 and the end of 2008.⁵ Meanwhile, the global capital cost index rose over 100% during the same period.⁶

Alaska-specific information obtained through public sources and shared in confidence during the Stranded Gas Development Act negotiations and through ACES reporting shows similar trends on the North Slope. Estimates of operating costs prior to PPT ranged from \$3 to \$5 per barrel. More recent information indicates that operating costs on the North Slope have doubled, and in some cases nearly tripled. Following the Prudhoe Bay corrosion incidents in 2006, operating expenditures on major repairs increased. However, since that time, the proportion of total operating expenditures directed to major repairs does not appear to have been a key driver in the growth of total operating expenditures.

Figure D shows the upward trend in per-barrel operating costs at Prudhoe Bay from 2003 to 2008. The chart shows a dramatic increase over the six-year period, consistent with cost increases seen in the oil and gas sector worldwide.

Figure D



The recent downturn of the global economy has started to push operating costs back down again. In June of 2009, CERA reported that worldwide, operating costs had declined 8 percent

⁵ IHS CERA Upstream Operating Cost Index (UOCI), <http://www.ihsindexes.com> (Accessed December 11, 2009)

⁶ IHS CERA Upstream Capital Cost Index (UOCI), <http://www.ihsindexes.com> (Accessed December 11, 2009)

over the previous 6 months.⁷ The most recent information reported to the department under the new ACES requirements shows this trend to also be developing on the North Slope.

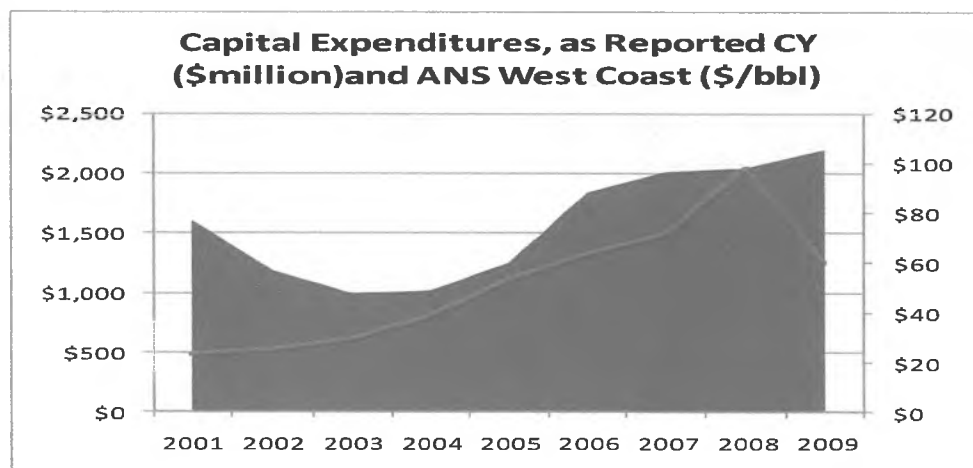
Much of this change can once again be linked to recent trends in oil prices. Lower oil prices led to a slackening of worldwide project activity, driving down the costs of transportation and various consumables. Despite this correlation, however, operating costs have not fallen at the same rate as oil prices. While the department anticipates that per-barrel operating costs will continue to decline under the lower oil price forecast for FY 2009 and FY 2010, they are expected to remain relatively high compared with those from five or more years ago.

Capital Expenditures

Capital expenditures have also increased since PPT and ACES were enacted. While capital expenditures on pipeline repairs at Prudhoe Bay increased after the Prudhoe Bay corrosion incidents in 2006, the majority of growth in capital expenditures is attributable to drilling, seismic and other projects. As shown below, capital spending on the North Slope in CY 2009 was roughly twice the level in either 2003 or 2004. At least some of this increase is due to new development activities. Two major developments – Oooguruk and Nikaitchuq – have gone forward despite recent oil price setbacks. Development of the Point Thomson field is also underway.

Figure E shows historical capital expenditures from CY 2001 to 2009 as reported by oil and gas producing companies operating on the North Slope.

Figure E



⁷ IHS CERA: "Period of Sustained Cost Escalation for Upstream Oil and Gas Facilities Comes to an End," June 5, 2009. <http://www.cera.com/asp/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10388> (Accessed December 11, 2009)

In order to forecast North Slope lease expenditures, the department receives forward looking spending projections from taxpayers, and also consults a variety of information sources, including unit forecasts, plans of development, and federal partnership returns. These data give the department significantly better insight into future development plans, as well as trends in operating and capital expenditures.

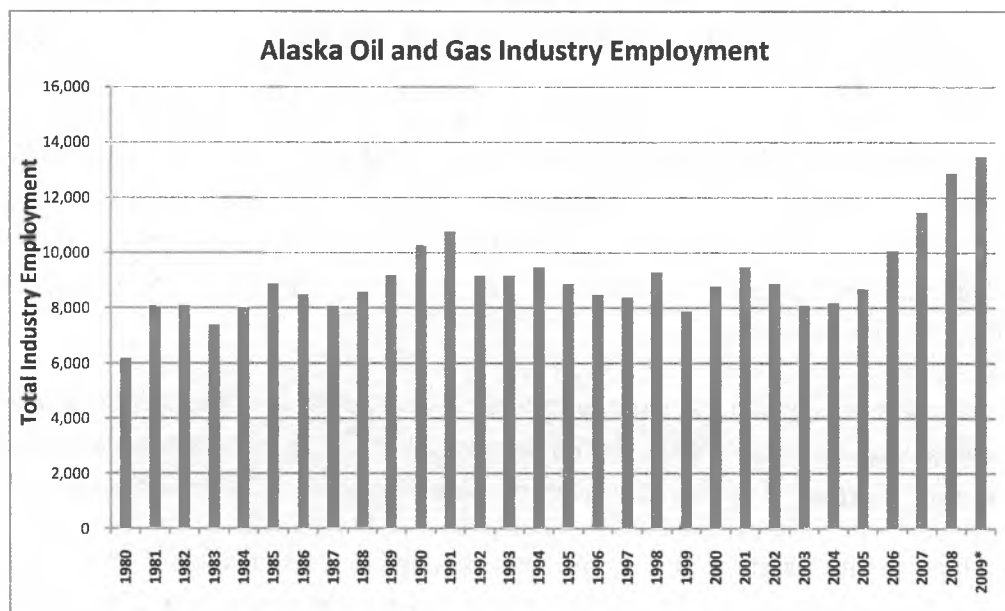
This information shows a variety of changes on the North Slope in the years ahead. There is continuing development of newer fields like Oooguruk, Nikaitchuq, and Point Thomson. Growth in capital expenditures at many major North Slope units (i.e. Prudhoe Bay, Kuparuk, Colville River and others) appear to slow slightly or decline in the next year or two and re-surge thereafter to the level of the recent past or higher. This trend is consistent with indicators of worldwide industry activity which show a dramatic drop in capital expenditures from the high levels experienced in 2008. This suggests that recent economic contraction may have caused some North Slope development projects to be delayed as producers hope to form a better idea of where the economy and oil prices may be headed.

It would be presumptuous to solely attribute the rise in expenditures to the success of the investment incentives found in ACES. Many factors beyond tax policy drive oil and gas investment decisions. However, one of Alaska's new explorers, Savant Alaska, stated in a recent Petroleum News article that ACES had assisted in their development efforts at Badami. "ACES was an important component for Savant in considering investment in Alaska. It definitely had its intended consequence with us." ⁸

Industry Employment

Employment in the industry has also increased steadily since the implementation of PPT and ACES, with 2009 forecast to be the highest in state history. It is important to note that this occurred concurrent with a steady rise in the oil prices, which has generally shown a strong correlation with industry activity.

⁸ Kay Cashman quoting Savant's Chief Operating Officer Greg Vigil, "Savant Accelerates Badami Drilling Plan," *Petroleum News*, Volume 14, No. 3, January 18, 2009.

Figure F⁹

Flexibility of Tax Burden Evidenced

The increased revenues generated under ACES represent an increased tax burden on Alaska's oil and gas industry. However, there is evidence that ACES effectively adjusts that burden when oil prices drop and profit margins are squeezed. In 2009, a period of relatively low oil prices in comparison to recent years, 35 percent of ConocoPhillips total reported exploration and production profit in the first quarter of the year (Q1), 55 percent in Q2, and 36 percent in Q3, came from its Alaska operations, which only account for 12 percent of the company's worldwide production.¹⁰

ACES Structure and Tax Rate

The ACES tax consists of a base rate of 25% plus a progressive surcharge, which is triggered when a company's net profits — also known as "production tax value" — exceed \$30 per barrel. Beyond this point, the base tax rate is increased by 0.4% for each additional \$1 increase in per-barrel production tax value. Using current estimated transportation and production costs of roughly \$26 per barrel, the surcharge would begin to be applied when west coast oil prices reach \$56 per barrel. When the combined base rate and progressive surcharge reach 50%

⁹ Data from Alaska Department of Labor and Workforce Development, Research and Analysis Section (January 11, 2010). Includes nonagricultural wage and salary data and excludes the self-employed. *Estimates for 2009 are preliminary.

¹⁰ ConocoPhillips, Form 10-Q Quarterly Reports Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934, March 31, 2009, June 30, 2009 and September 30, 2009.

(approximately \$92.50 per-barrel profit or \$118.50 West Coast price) the progressive surcharge is lessened to 0.1% for each additional \$1 increase in per-barrel production tax value. The maximum nominal tax rate is 75%, which would apply at a profit rate of \$342.50 per barrel or \$368.50 West Coast price.

As with any tax, ACES may be evaluated using a variety of different metrics, including “effective,” “nominal” and “marginal” tax rate comparisons. While each of these can be helpful under the appropriate circumstances, each is also subject to certain limitations. It is important when using these metrics to understand their relative value and how they reflect upon the objectives of the tax system.

The “effective tax rate” is the share of the total gross taxable value at the point of production that is paid in production taxes after credits are applied. It is a good universal measure of the sharing of total petroleum value that can be compared to gross value-based tax systems.

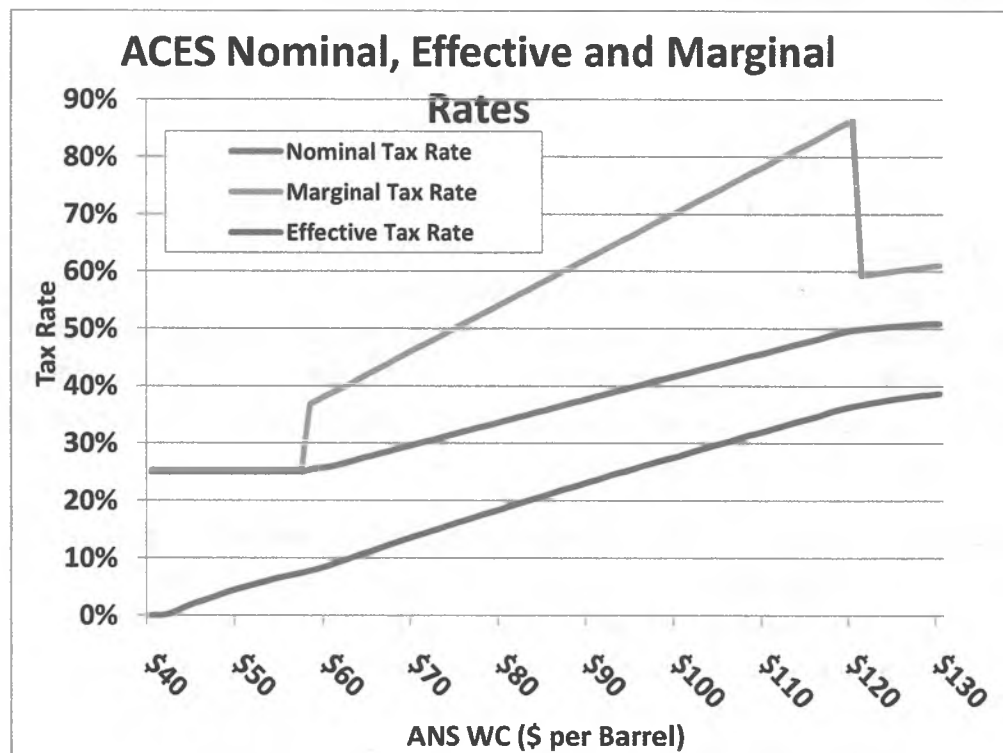
The “nominal tax rate” is the statutory tax rate as applied to the net value of oil and gas production. It does not account for credits or other tax benefits which ultimately impact a company’s bottom line. Under ACES, the nominal tax rate varies with the per-barrel profitability. In addition to a base tax rate of 25%, ACES levies a progressive surcharge that can raise the combined nominal tax rate to 75% at extreme price levels.

The “marginal tax rate” is the rate theoretically applied to each dollar increase in oil price. In the case of ACES, the marginal tax rate is 25% until per barrel profit reaches \$30 per barrel (about \$56 per barrel in west coast spot price under the current cost structure), at which point it increases for every additional dollar up to a marginal tax rate of 87% when the profit reaches \$92.50 per barrel (about \$118.50 per barrel on the west coast). Following this peak, the marginal tax rate drops off significantly as the profit level continue to rise. With a net based tax system, this metric shows a company the impact of making additional investment, because each dollar they invest is “subsidized” by the government based on the amount of marginal tax they have avoided paying on that dollar.

Each of these metrics has their limitations when considered in isolation from other metrics, or when only one data point on the curve is presented. For example, a marginal tax rate of up to 87% initially sounds excessive. However, at that same price level, the effective tax rate (the tax burden) is less than 40%. The marginal rate of 87% actually represents the state’s “portion” of any new investment made at such high prices.

Figure G shows the nominal, effective and marginal tax rates under ACES using a wide range of west coast spot prices.

Figure G



Production Tax Administration and Implementation

The passage of ACES presented significant challenges for tax administration and implementation because it involved comprehensive structural changes to the tax on the heels of the prior year's legislative changes through PPT. These challenges are experienced both on the taxpayer and on the state side.

Tax Credit Successes and Difficulties

The increased spending levels reported earlier in this document, may be due in part to the expansion of capital and exploration credits provided under ACES for reinvestment in the state. Credits can be applied against tax liabilities, sold to other companies or, for companies producing less than 50,000 boe/day, can be purchased by the state. Nearly \$550 million in credits were claimed in FY 2009. Approximately \$193 million was paid to oil and gas companies

to purchase oil and gas tax credits, while an additional \$350 million in tax credits were used to offset tax liabilities.

Some administrative difficulties have arisen due to the requirement that the 20% capital credit be spread out over two years. It has taken a substantial amount of time and resources to develop a database with which the division can track the issuance and staged application of these credits for each taxpayer. This detailed tracking was made necessary by the transferability and use of the credits, and some confusion by taxpayers and their transferees regarding how the credits could be applied. In addition, the two-year spread in the application of the capital credits diminishes their value to taxpayers who look for quick return of their investment dollars. Finally, one of the reasons for the two-year spread in credits was to assist the department in forecasting future revenues. However, the department has found that the information provisions in ACES have been extremely valuable and successful in improving the volume and quality of spending projection data provided to the department by operators. This forward looking spending information has been much more valuable to the revenue forecasting process than the two-year spread in credits.

The Department has also received feedback regarding the reinvestment requirements for new explorers. Under current law, companies generally receive a financial benefit of over 45 percent of exploration expenditures incurred in the state. However, a new entrant to Alaska (with no production to immediately apply the credit against) can only get full value for their expenditures by applying to the state for cash payment for their credits earned. In order to receive such a payment, the company must continue to make expenditures in future years. Although this provision was originally created to support new explorers, it appears to be a limiting factor for companies that have fewer financial resources and are only considering a single exploration investment. In application, this requirement creates a "double standard" where new entrants to Alaska are provided less value for their credits compared to incumbent companies.

"Standard Deduction" provision at AS 43.55.165(j)

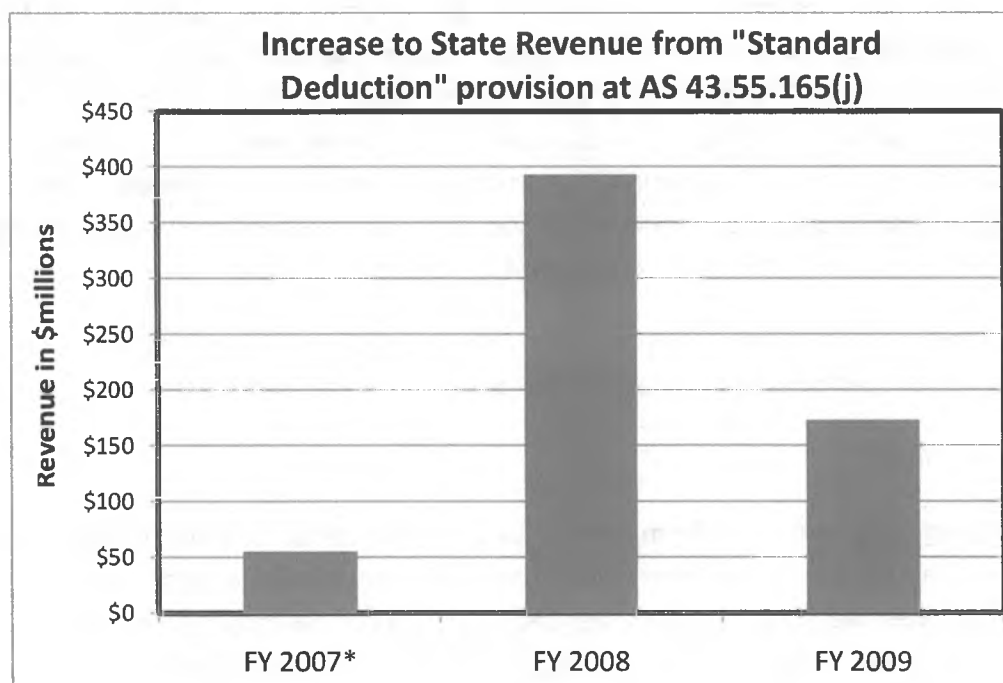
The ACES tax reform made modifications to the deductibility of operating expenditures for certain fields on the North Slope. Alaska Statute 43.55.165(j) limited the deduction of operating expenditures at leases or properties that have produced a cumulative 1 billion barrels of oil and NGLs since the lease or property began oil production. The Prudhoe Bay Unit and the Kuparuk River Unit are subject to these provisions based on their cumulative production. The provision, coined the "standard deduction," limits the deduction of operating expenditures to the amount deducted on the first PPT returns, filed April 1, 2007, for calendar year 2006 expenditures, adjusted annually. This provision, which was effective through December 31,

2009, was intended to moderate the risk associated with adopting a profits based tax without substantial historical data on which to rely for future cost estimates.

Based on company-reported expenditure data, the provision has resulted in a substantially greater tax liability to the state during the time it has been in place. The total liability in FY 2008 was substantially larger than the liability for FY 2009 due to the higher tax rate in FY2008 because of higher net profits realized due to high oil prices.

Figure H shows the increased revenue to the state from the standard deduction from FY 2007 through FY 2009.

Figure H¹¹



Regulations

The ACES tax included new restrictions and guidance on allowable lease expenditures, requiring complex regulations. The department has actively sought industry input on the structure of the regulations to ensure they continue to achieve their intended purposes, while avoiding undue burdens for either side. The process has included numerous public workshops pertaining to credit regulation, conforming regulatory changes required by ACES, lease expenditures, facility sharing costs and transportation costs. As a result, the regulation drafting process has been

¹¹ *Standard Deduction was only in place for half of FY 2007.

lengthy and complex. However, the regulations to define allowable lease expenditures are expected to be finalized this month.

Under the statute the regulations are retroactive to various 2007 dates. To the extent additional taxes are due, taxpayers would be required to pay interest on what would now be late tax payments. The department has discretion to waive any penalties for late payments. However, a statutory change would be needed in order for the department to provide a waiver from interest payments.

Reporting and Revenue Forecasting

ACES requires that companies exploring for or producing oil and gas in the state submit a monthly information report to the department. This report includes estimated data on production volumes, the value of the production, and the operating and capital expenditures related to production. The monthly report is used primarily by state economists to monitor company production and spending. Included with the monthly report is an estimate of taxes owed and credits earned. Twice annually, companies are asked to provide the department with forward-looking expenditure information, along with future production plans to aid the department in providing the legislature with state revenue forecasts.

These reports, in combination with the monthly information reports and the annual tax returns, have significantly enhanced the quality of the department's revenue forecasts.

Audit Compliance

The ACES legislation extended from three to six years, the period in which the department is required to assess production taxes owed. The extension was seen as necessary to assure proper tax assessments, particularly given the complexity of overlapping ELF, PPT and ACES tax laws. The new tax law also included funding for four new "Audit Masters" within the department. The department is still experiencing significant difficulties recruiting and filling audit positions. The department has successfully recruited three Audit Masters, and these individuals have been placed within sections of the Tax Division to assist with implementation and administration of the tax. The recruitment of the fourth Audit Master, and Oil and Gas Revenue Auditors is ongoing.

During 2008, the department's auditors began auditing tax returns that were submitted for calendar year 2006 under the PPT program.

Conclusion

The ACES production tax has been effective in allowing the state to share in the benefits of high oil profitability. It has also responded well to lower oil prices by reducing state tax burden on Alaska's oil and gas producers. Over \$2 billion in new capital investment was reported in fiscal year 2009 reaching near-record levels. While these and other indicators suggest that the profits-based tax system has supported North Slope exploration and development, it would be misleading to suggest that ACES alone influences the level of investment. While tax is recognized as being an important factor in investment decisions, it is not the primary determinant. Long-term price forecasts, as well as the resources themselves, have proven to be much more significant drivers of industry activity.

The department is continuing to analyze ACES to identify opportunities to improve the tax framework in order to support additional exploration and development in the state, while not harming the state's revenue base.

The new reporting requirements under ACES are helping the department develop a better understanding of industry expenditures and activity, and have assisted in the state's revenue forecasting efforts. Development of new tax regulations is progressing, though several challenges remain for both the state and taxpayers. Numerous workshops have been held to solicit industry input and these will continue as the department continues to work through outstanding issues. In 2008, the production tax audit group began auditing taxpayers who submitted annual returns for CY 2006 under PPT.

Overall, the information reviewed by the department indicates that ACES is performing as expected when it was passed by the Legislature in 2007. The economic provisions are resulting in the revenue levels anticipated, and the investment incentives appear to distribute the increased tax burden in a fashion that continues to encourage reinvestment, though the experience with the credit program could be improved for new explorers. Challenges remain in the implementation by the department, but they are manageable and the department is positioned to meet those challenges.

7.

**DOR's Oil & Gas
Production Tax
Status Report
Jan. 18, 2011**

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



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Oil and Gas Production Tax
Status Report to the Legislature
Alaska Department of Revenue
January 18, 2011

Report Purpose

In August 2006, the 24th Alaska state legislature approved House Bill 3001, which represented a major restructuring of the state's oil and gas production tax. As part of the legislation, lawmakers asked that the Department of Revenue study the impact of the production tax changes on several criteria and produce a report on or before the first day of the 2011 legislative session on the findings of that study.¹ This report summarizes those findings.

Executive Summary

This report evaluates six elements of Alaska's production tax system since implementation of the Petroleum Profits Tax (PPT) in 2006 and Alaska's Clear and Equitable Share (ACES) in 2007. The six elements and our key findings with respect to each of them are described briefly below.

- 1. Revenue Generation/Tax Rate** – State revenues under PPT and ACES exceeded the amount that would have been received under ELF for each of the four fiscal years since implementation of a net profits tax. Although the production tax rate under ACES may be as high as 75%, tax rates in each of the

¹ **AS 43.55.180 Required Report.** (a) The department shall study

(1) the effects of the provisions of this chapter on oil and gas exploration, development, and production in the state, on investment expenditures for oil and gas exploration, development, and production in the state, on the entry of new producers into the oil and gas industry in the state, on state revenue, and on tax administration and compliance, giving particular attention to the tax rates provided under AS 43.55.011, the tax credits provided under AS 43.55.023 - 43.55.025, and the deductions for and adjustments to lease expenditures provided under AS 43.55.160 - 43.55.170; and

(2) the effects of the tax rates under AS 43.55.011 (i) on state revenue and on oil and gas exploration, development, and production on private land, and the fairness of those tax rates for private landowners.

(b) The department shall prepare a report on or before the first day of the 2011 regular session of the legislature on the results of the study made under (a) of this section, including recommendations as to whether any changes should be made to this chapter. The department shall notify the legislature that the report prepared under this subsection is available.

four years were much lower than the maximum rate.

The oil tax rate of 5% of the gross value at the point of production at AS 43.55.011(i) for private landowners has not raised any significant concerns that have been communicated to the Department of Revenue.

2. **Industry Investment** – Investment in the form of capital expenditures has increased in each of the four fiscal years since implementation of the net profits tax, however, it is unclear how much of the capital expenditures were drilling or well-related and how much were maintenance or facilities-related.
3. **Impact on Exploration, Development, and Production** – Exploration has generally increased from 2003, when the EIC credit was implemented, but has dropped off in 2010. Development continues in three relatively new North Slope projects, yet production continues to decline.
4. **Industry Employment and New Entrants** – Industry employment rose steadily from 2006 through 2009, but dipped slightly in 2010. The number of companies filing annual tax returns doubled between 2006 and 2009, indicating interest by companies that are either new or returning to the Alaska oil and gas industry.
5. **Use and Expansion of Tax Credits** – The amount of credits used has increased annually since 2006 and we expect the trend to continue as new credit programs were added in the 2010 legislative session.
6. **Tax Administration and Compliance** – The department continues to write regulations for the new tax system, and the first audits under the net profits tax have been completed. The department has, however, been hampered in its tax reporting and compliance efforts by the lack of a centralized database to house and manage the large volumes of oil and gas data it receives.
7. **Conclusions and Recommendations** – Based on the multiple changes to the tax laws over the past few years, drawing any conclusion about their effect on Alaska's investment climate is difficult. However, what is clear is that production continues to decline. The state should continue to monitor its competitiveness with other oil and gas jurisdictions worldwide and be prepared to change its tax structure as needed.

Overview

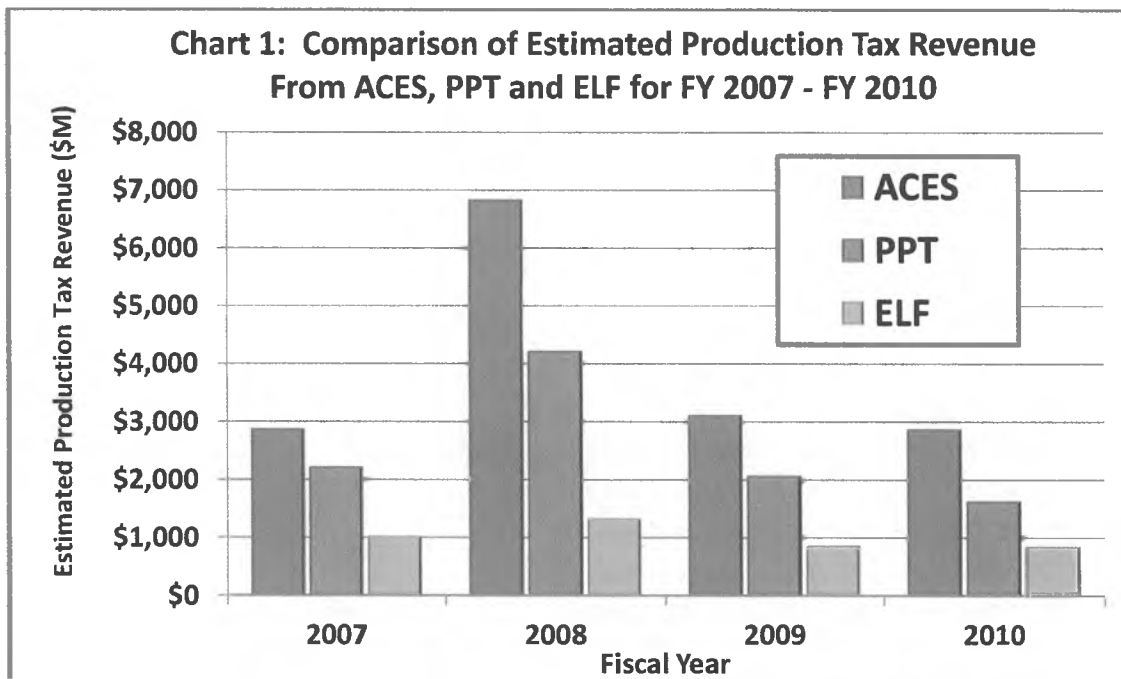
This report reviews and summarizes information gathered over the approximate five-year period since the implementation of the Petroleum Profits Tax (PPT) in 2006, and in 2007, Alaska's Clear and Equitable Share (ACES). The report covers six critical elements for evaluation and a section with conclusions and recommendations, as follows:

1. Revenue Generation/Tax Rate
2. Industry Investment
3. Impact on Exploration, Development and Production
4. Industry Employment and New Entrants
5. Use and Expansion of Tax Credits
6. Tax Administration and Compliance
7. Conclusions and Recommendations

Revenue Generation/Tax Rate

Both PPT and ACES have generated more production tax revenue for the State than would have been received under the previous production tax system, which used the Economic Limit Factor (ELF). In the one year that PPT was in place, FY 2007, the production tax totaled \$2.2 billion. That year, the ANS West Coast oil price averaged \$61.60 and production on the North Slope averaged 734,000 barrels per day. In contrast, the average oil price one year earlier, in FY 2006, was \$62.12, production averaged 840,000 barrels per day, and the production tax under ELF totaled \$1.2 billion--\$1 billion, or 45% less than collected under PPT. It should be noted that PPT became effective on April 1, 2006, adding two months of tax collections to the FY 2007 total, making FY 2007 effectively a 14-month fiscal year. Regardless, the level of PPT collections above those that would have been collected under ELF, at least at moderately high prices, is significant.

In the three years that ACES has been in place, production tax revenues have increased to higher levels than under PPT. This is largely because ACES has higher base and progressivity tax rates than did PPT, and because one of the credits under PPT – the transition investment expenditure credit – was reduced substantially. The chart below shows production tax revenue collections under PPT and ACES as compared to how production tax revenue collections would have looked under two tax systems that were not in place during those years.



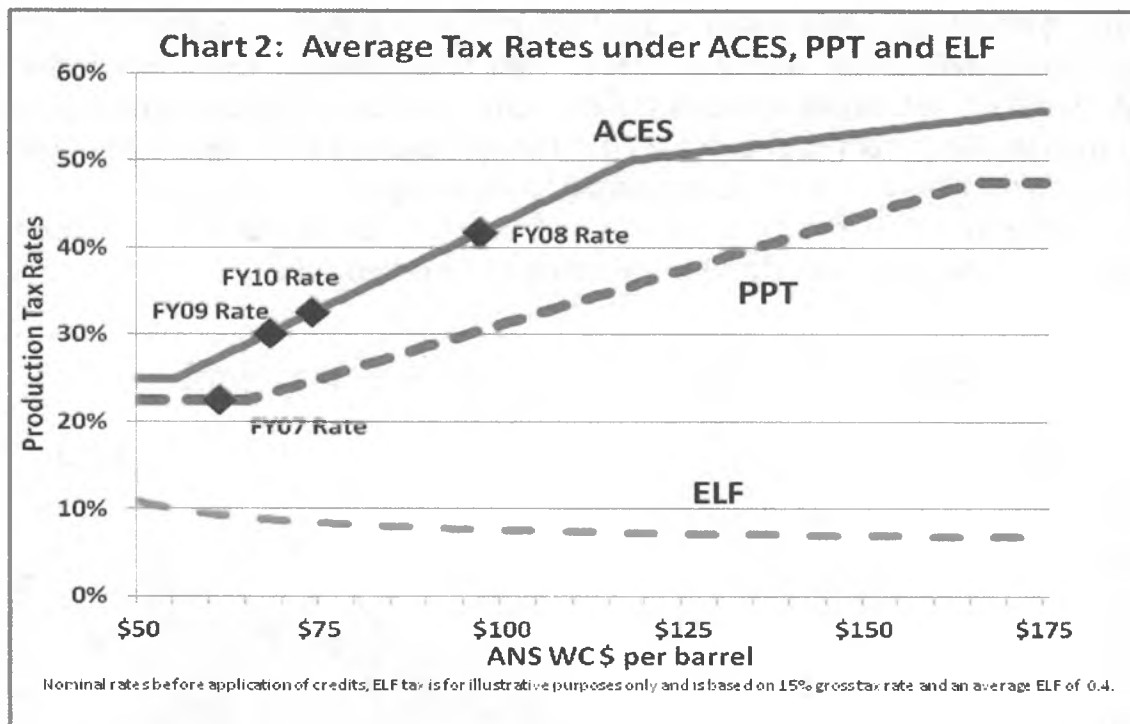
Production tax under both PPT and ACES is calculated on the net profits of oil and gas production, whereas ELF production tax was calculated on the gross profits of oil and gas production. Relative to taxes based on the gross value of production, net profit tax systems generally provide more tax revenue when oil prices are high and less tax revenue when prices are low. The progressive tax mechanism, designed to increase the total tax rate when per-barrel profit exceeds a pre-determined threshold, can increase the tax rate substantially. In addition to the progressive tax rate, the per-barrel profit level where the progressive tax is triggered is important. In the case of ACES, the progressive tax trigger is \$30 net profit per barrel, whereas with PPT, the progressive tax trigger was \$40 net profit per barrel.

Alaska North Slope (ANS) oil prices over the past four fiscal years were high relative to previous fiscal years. ANS crude prices over the four fiscal years of 2007 through 2010 averaged about \$75 per barrel compared to \$42 per barrel for the fiscal years of 2003 through 2006. Under ACES, an average price of \$75 per barrel would yield an average profit of \$50 per barrel, producing a combined base and progressivity tax rate of 33% ($25\% + [(\$50 - \$30) \cdot 0.04]$). The tax under this scenario before credits would be \$16.50 per barrel. In contrast, the tax rate under ELF of 15% of the gross value at the point of production, even if the ELF calculated to 1, would yield a production tax of \$10.50 per barrel, assuming transport costs of \$5 per barrel.

When oil prices are low, however, a net profits-based tax structure would likely provide less production tax revenue than a gross profits-based tax. For example, a tax of 15% on the gross value, regardless of profit, could create a loss for companies producing oil

if profits were equal to or less than the tax. Because PPT and ACES recognize the costs of production in their calculation, a company with no profit would not pay any production tax and would likely get tax credits to offset future tax liabilities. Low oil prices experienced late in the year 2008 and early 2009 generated tax liabilities for many companies operating on the North Slope that were lower than they would have been under the ELF system.

Chart 2 below shows the average tax rates of PPT, ACES and ELF under a range of oil prices. Also shown is the average tax rate in each of the years that a net profits tax has been in place.



The department was also asked to review the tax rate for oil produced from private land of 5% of the gross value at the point of production.² The department is not aware of any concerns expressed on behalf of industry or private landowners as to the fairness of this tax.

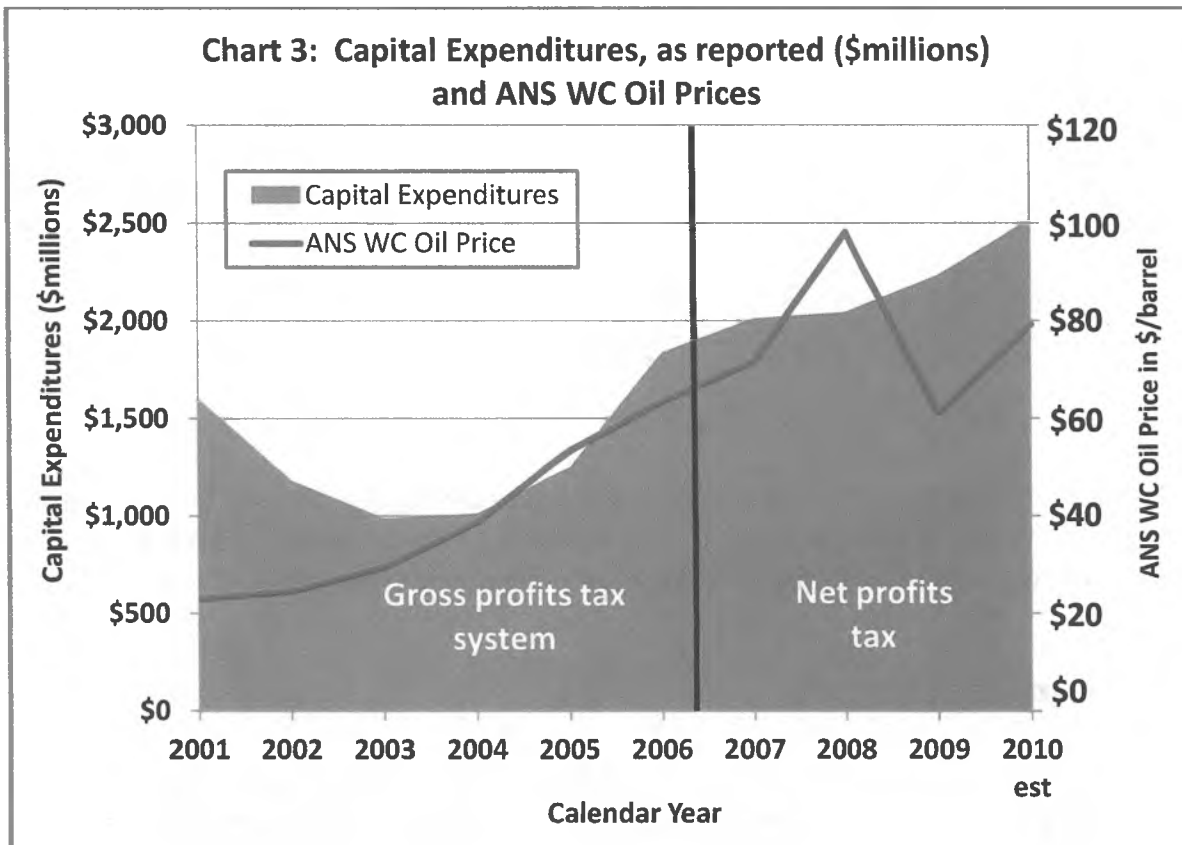
Industry Investment

Investment is an important component in Alaska's oil and gas industry. Producing oil, especially in an arctic environment, requires substantial financial outlays before, during

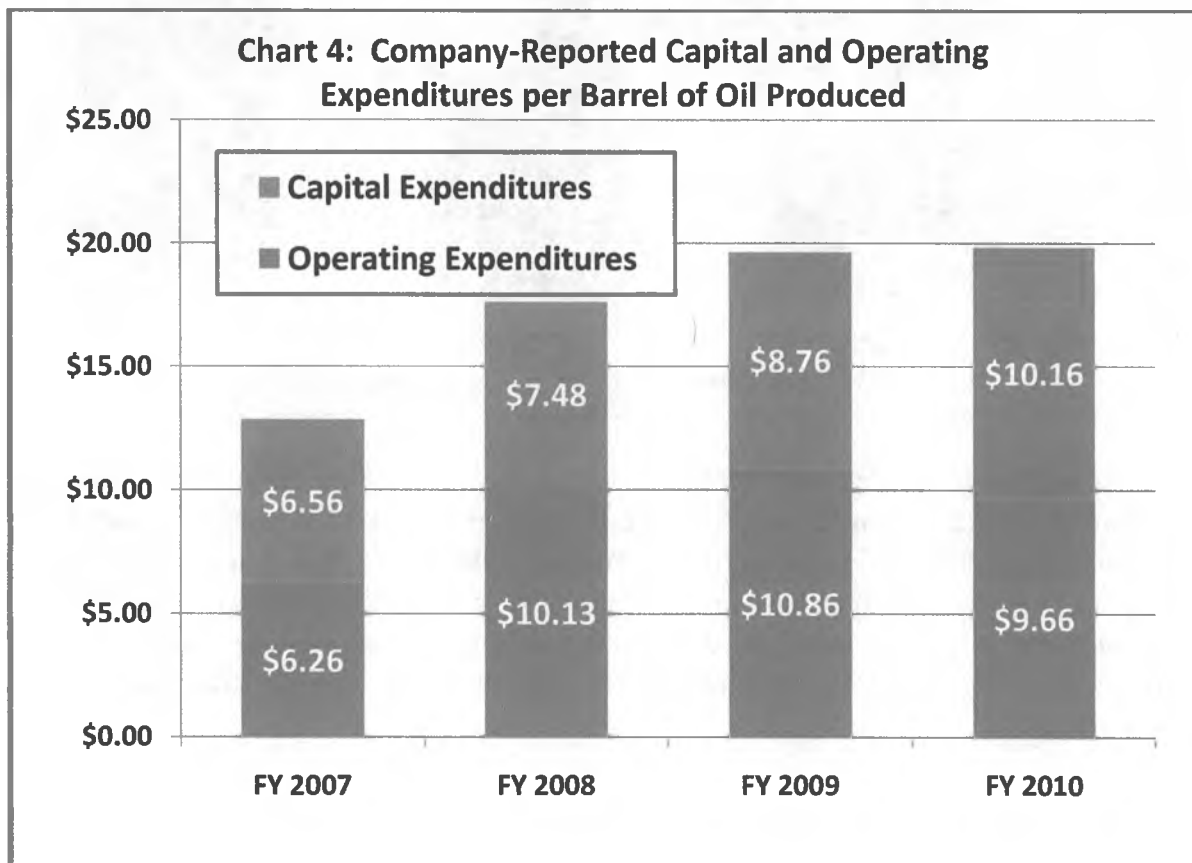
² AS 43.55.011(i)

and after producing the oil. In massive oil fields such as Prudhoe Bay, which has been operating for more than 30 years, maintaining and upgrading equipment and facilities is key to continued undisrupted oil production. Companies must also invest in research and new technologies in order to achieve the maximum recoverability of petroleum from the reservoirs they have developed. Because the companies that invest in petroleum projects can and do operate in areas outside of Alaska and the country, Alaska oil projects must compete with other petroleum opportunities throughout the world for those investment dollars.

Industry investment is generally reflected in capital expenditures, as opposed to operating expenditures, which are normally considered day-to-day expenditures for producing oil and gas. Alaska's fiscal system, which gives credits for capital expenditures, theoretically encourages these types of investments. Our review of the past 10 years of data appears to bear this out. Chart 3 below shows company-reported data from tax filings from calendar year 2001 through calendar 2010 (estimated). While capital expenditures over the five-year period (2006 through 2010) since the implementation of a net profits tax with credits for capital expenditures have increased each year, we have limited data as to the nature of the expenditures.

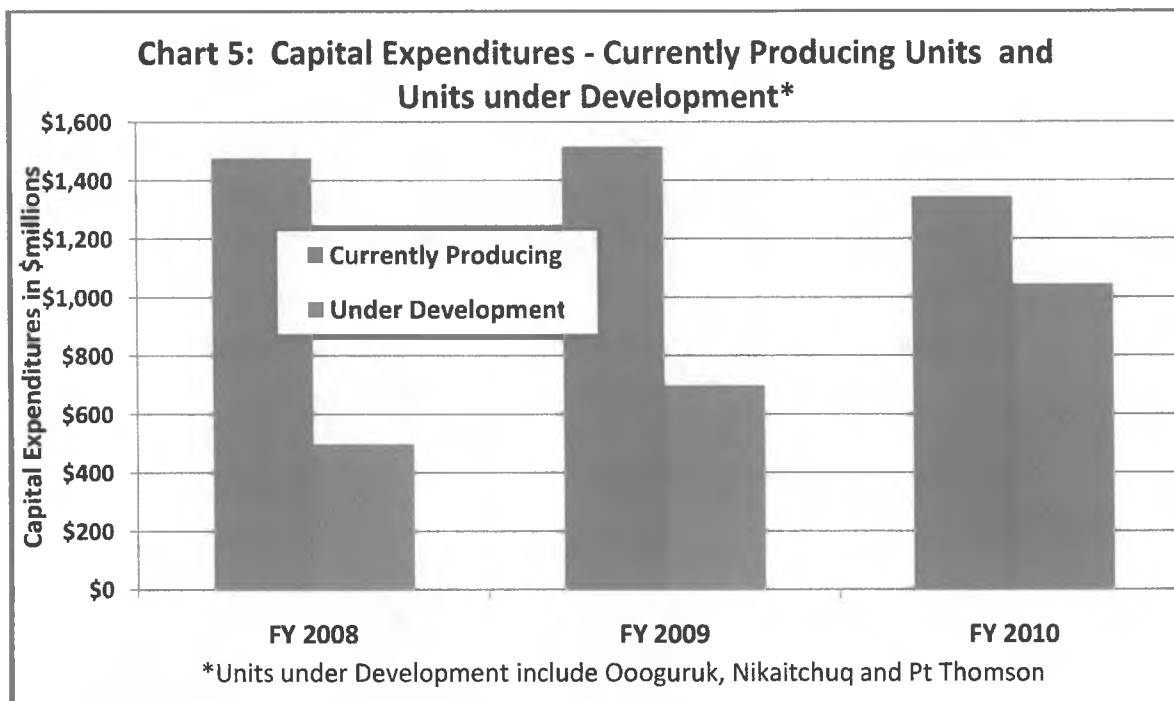


In the context of petroleum basin operations, capital expenditures are generally an indicator of expanding production or enhancing or extending the life of facilities or equipment. Expenditures for drilling wells normally fall into the category of capital expenditures as do expenditures for building housing or processing facilities. The Department of Revenue has extremely limited data from which to determine the nature of the capital expenditure increases. Given the age of North Slope facilities and infrastructure, it is quite possible that much of the capital investment in currently producing properties such as Prudhoe Bay is to extend the life of the facilities or infrastructure. Production on the North Slope continues to decrease, with a 7% decline rate between FY 2009 and FY 2010. The end result is that capital expenditures per barrel of oil produced are rising, while operating expenditures per barrel have leveled off and even decreased somewhat, as shown in Chart 4 below.³



³ The slight decline in capital expenditures per barrel between FY 2007 and FY 2008 can be explained by the fact that FY 2007 included 14 months of expenditures, due to the effective date of the tax change of April 1, 2006.

One trend that has been observed in annual capital expenditures figures is that the proportion of capital spending in units under development has been increasing relative to the total capital expenditures spent on the North Slope. Chart 5 below shows expenditures by currently producing units and units under development over the past three fiscal years.

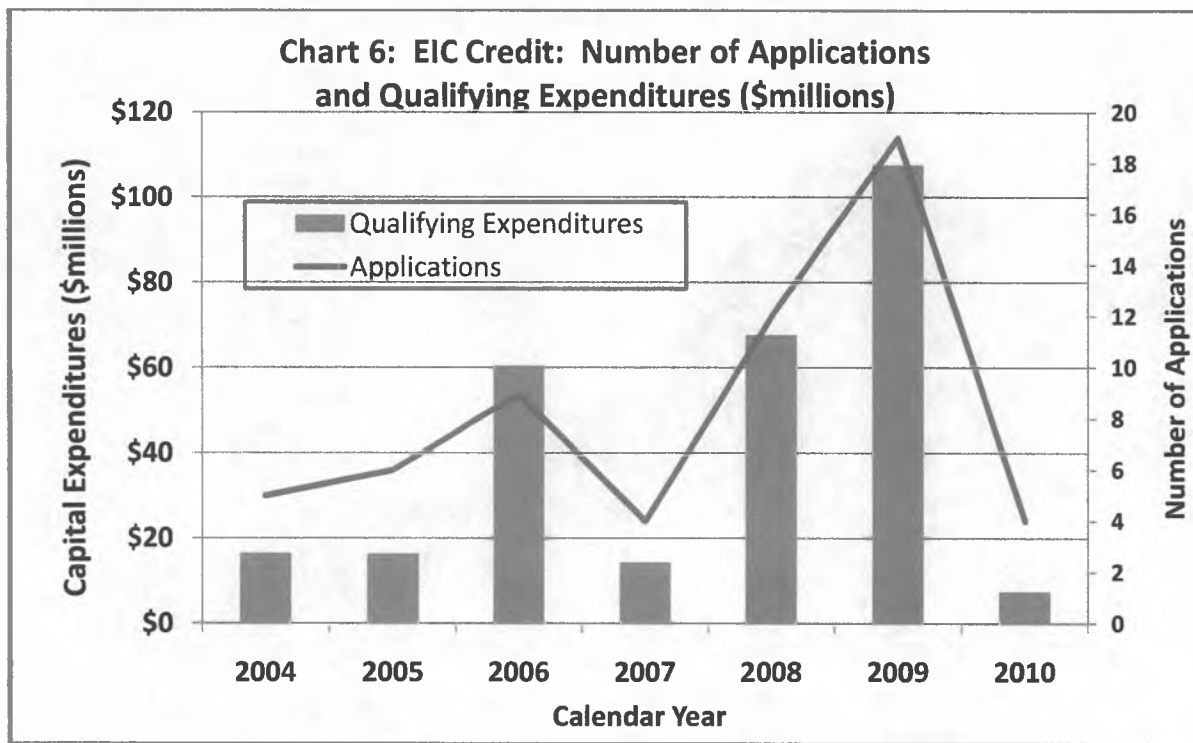


Capital expenditures also earn credits under the new production tax system. The credit system for capital expenditures on the North Slope does not distinguish between types of capital expenditures in existing units. The legislature in 2010 expanded the credit program in Cook Inlet to include an additional 20% credit (total of 40% credit) for lease expenditures related to wellwork. A credit increase of this nature may also prove beneficial to incentivize capital expenditures on drilling and increased wellwork on the North Slope.

Impact on Exploration, Development and Production

As discussed in the previous section, the net profits tax system includes credits for capital expenditures, without distinction as to the nature of the expenditure. The tax system also includes credits for exploration expenditures through its exploration incentive credit (EIC) at AS 43.55.025. This credit was implemented in 2003 and was expanded with the ACES tax changes. If a project meets certain exploration criteria, it may be eligible for 40% credit under the EIC program.

The department began receiving applications under the EIC program in 2004, and the number of applications and amount of qualifying expenditures has generally increased each year peaking in the winter of 2008/2009⁴. The number of applications for EIC credit decreased significantly in 2010, reflecting a decrease in activity for the winter of 2009/2010. Chart 6 shows the number of applications and the expenditures that qualify under the EIC program from 2004 through 2010.

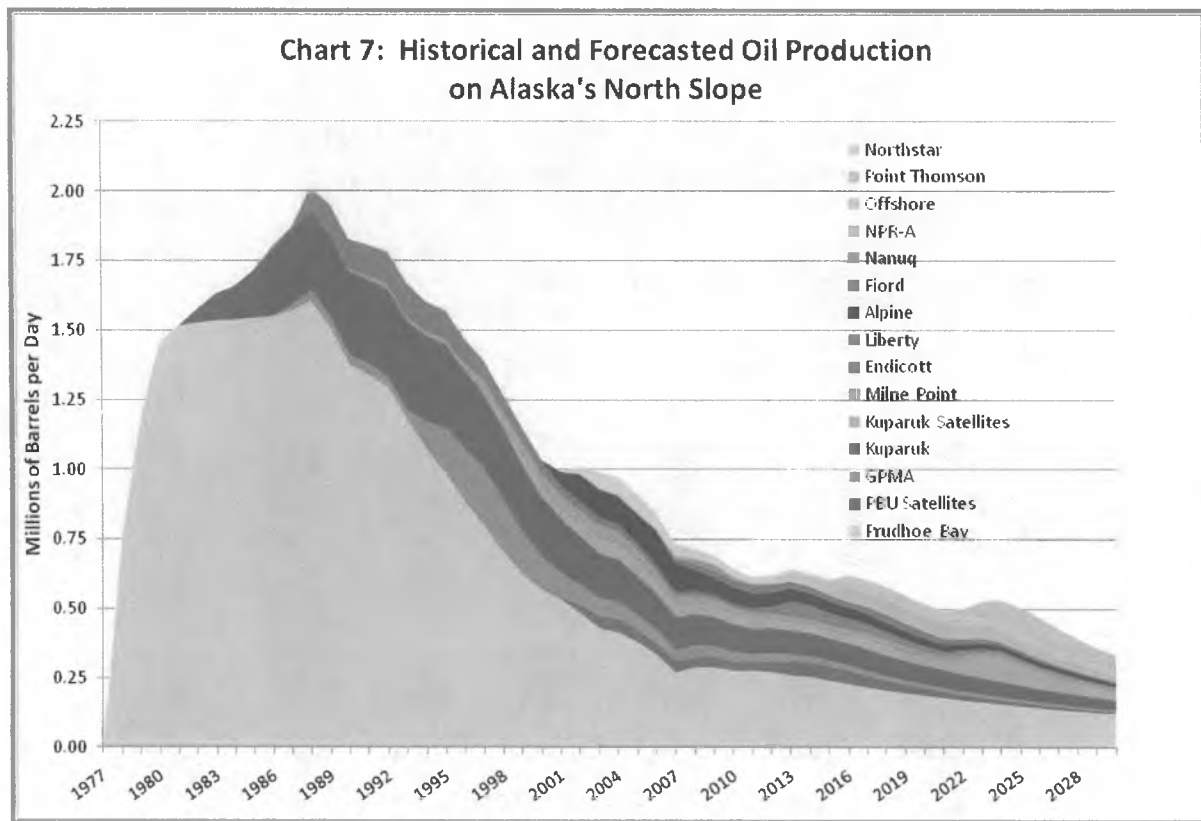


It is much more difficult to measure a tax system's impact on oil development and production from existing fields. The department's production forecasters twice annually create production profiles from limited information about an area's geology, drilling results, and other information exchanged in confidential discussions with operators. The compilation of production profiles for each North Slope field is a challenging task, employing the use of an engineering consultant, generally accepted engineering principles, and special software. The results of this compilation are subject to further revision as projects face delays that are typical in the petroleum industry such as reservoir challenges, permitting difficulties or lack of project funding.

New commercial developments on the North Slope include the Oooguruk Unit, which began production in 2009, and the Nikaitchuq Unit, which is expected to begin production in 2011. The Point Thomson Unit is also under development, expected to

⁴ The sharp decrease in 2007 may be due to the tax change to the PPT, which at the time provided credit equal to the lower credit rate of the EIC program, without the reporting requirements.

begin production in 2015. Despite the addition of these developments, North Slope production continues to decline. From FY 2009 to FY 2010, oil production declined 7%; another 4% decline is projected between FY 2010 and FY 2011. Chart 7 below shows historical and projected oil production from the North Slope.

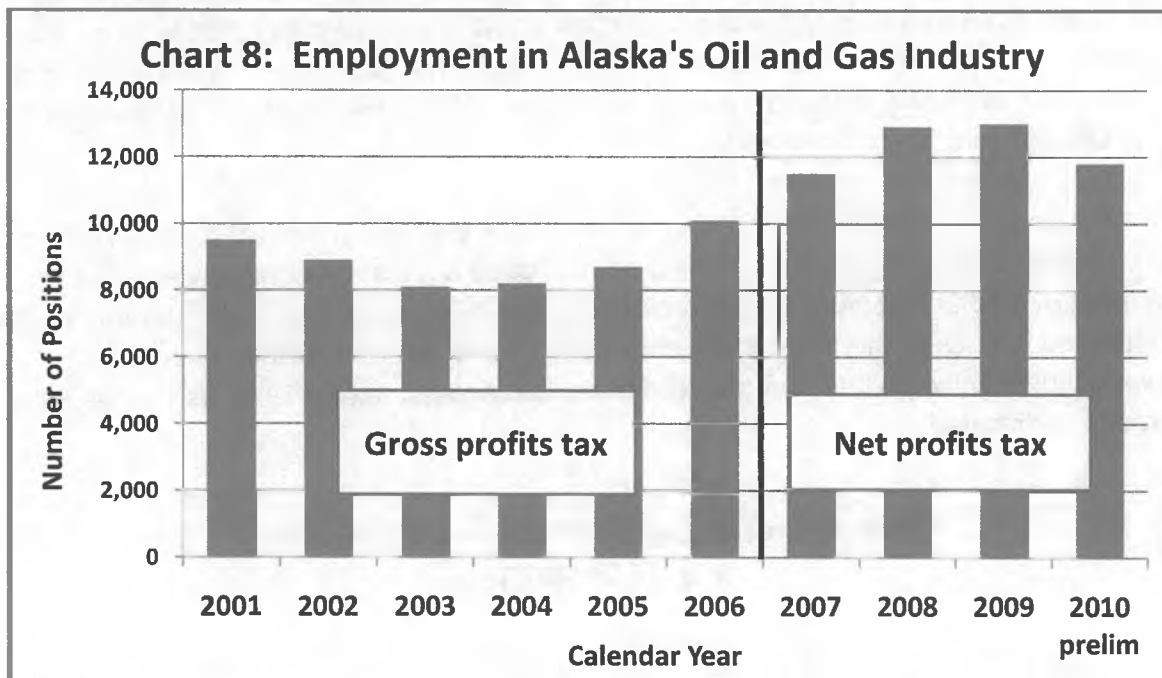


Industry Employment and New Entrants

Employment in the oil and gas sector is another important measure of the health of the oil and gas industry in Alaska. Although oil and gas employment is not the largest category in the state, it is among the most sought-after employment, due to high wages. The Alaska Department of Labor and Workforce Development (DOLWD) reports that in 2009, the average earnings for a person employed in the oil and gas extraction industry was close to \$14,000 per month. These earnings are more than 3 times higher than the average earnings for all industries and government in the state of about \$4,000 per month.

The department also reports number of employees by industry. Oil industry employment in the state includes jobs with duties that would fall into one of three categories: (1) oil and gas extraction; (2) drilling oil and gas wells; and (3) support activities for oil and gas operations. Officials at DOLWD acknowledge that the definition

is fairly narrow, leaving out important oil-related employment, such as jobs at Alyeska Pipeline Service Company and at refineries in the state. Employment in the oil and gas industry has increased in the years since PPT was implemented, although the department projects a slight decrease in 2010. These data are shown in Chart 8 below.



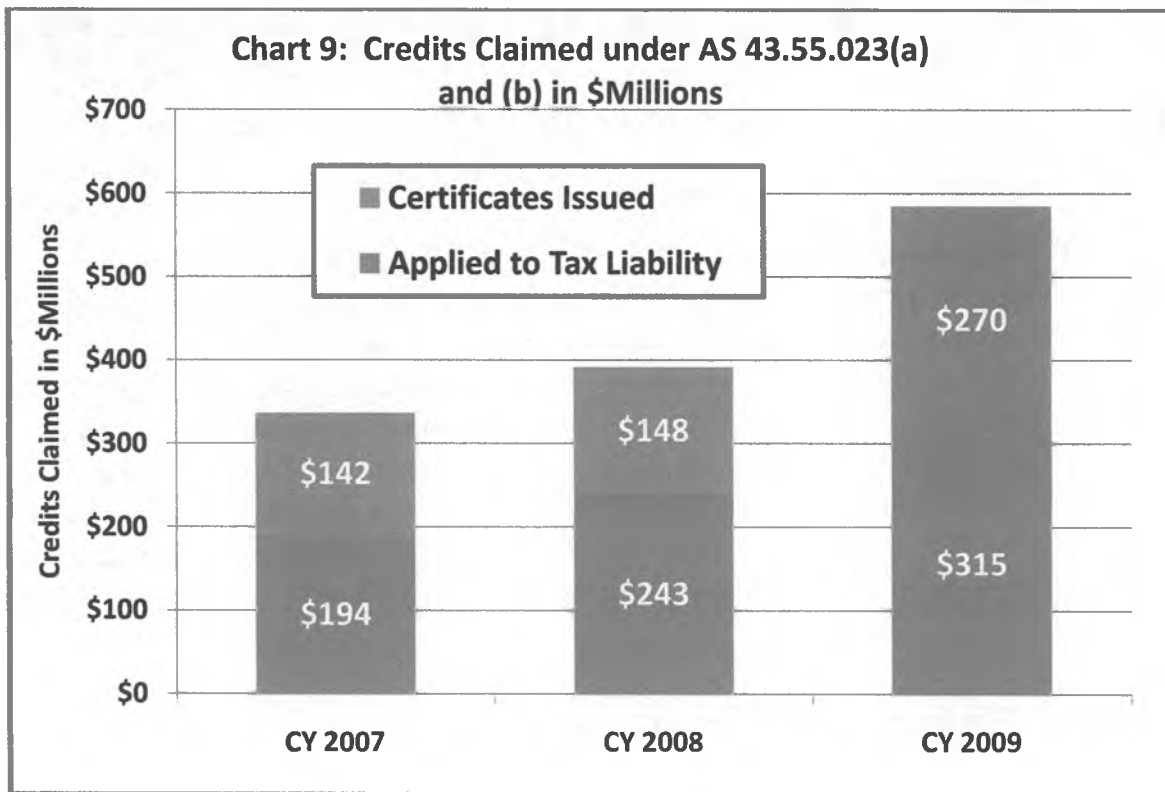
The state has seen new entrants into the Alaska oil and gas industry since the implementation of a net profits production tax. At the most recent lease sale held in October of 2010, a company new to Alaska successfully bid on over 100 tracts of oil and gas property. The steadily increasing number of production tax returns filed annually also indicates companies' new or renewed interest in Alaska's oil and gas opportunities. In 2006, the first year that filings were made under a net profits tax, there were 19 companies filing annual returns. In 2007, the number of companies filing production tax returns totaled 26, and in 2008, 36 companies filed annual production tax returns. The filing for 2009 increased only slightly from 2008, with 39 companies filing returns.

Use and Expansion of Tax Credits

Tax credits have played and continue to play an important role in the net profits production tax system. There are currently five credit programs specific to the oil and gas production tax, and each of the programs have had substantial interest, and in most cases, use from taxpayers. Alaska's tax credit programs are intended to steer spending to certain in-state activities.

The most widely used credits under the production tax system are the qualified capital expenditure credits at AS 43.55.023(a). Tax credits under this program may be applied to production tax to reduce a taxpayer's tax liability. If an oil and gas company has no tax liability, the credit may be carried forward, transferred to another company, or sold to the state. AS 43.55.023(b), credits for carried-forward net operating losses, are also widely used and may also be carried forward, transferred to another company, or sold to the state. Combined, these credits made up over 80% of the credits issued by the DOR Tax Division over the past three years.

Chart 9 below shows the total number of tax credits claimed under AS 43.55.023(a) and (b), categorized by the number of tax credits applied against a tax liability and the number of credits that were issued credit certificates for future use. We note that credits increased in each of the three years shown. The forecast for increased capital expenditures will translate to more credits applied against tax liabilities as well as more credits certificated.



Other credits include Small Producer/New Area Development credits (AS 43.55.024(a) and (c)) and Alternative Credit for Exploration (AS 43.55.025). These credits have seen less use than the credits under .023.

Credits have been expanded – both in credit rate and number of credits available – over the past year. The credit rate under the Qualified Capital Expenditure credit (AS 43.55.023) was increased for well lease expenditures relative to projects in Cook Inlet from 20% to 40%. Credit under the corporate income tax was also increased and extended (AS 43.20.043) for exploration and development of natural gas in Cook Inlet. The credit rate increased from 10% of qualified capital expenditures and qualified services to 25% of these costs and the credit program was extended from 2013 to 2016. For a complete listing of tax credits available against the production tax and other taxes, see the Fall 2010 *Revenue Sources Book*, at:

<http://www.tax.alaska.gov/programs/documentviewer/viewer.aspx?2126f>

Tax Administration and Compliance

The numerous changes associated with the shift from a tax on gross value to a tax on profits have been a challenge for the Department of Revenue in a few specific areas. The first order of business under a tax system with a new, different way of calculating the tax is to define the inputs. This has taken place over the past several years in the process of creating, vetting, and implementing regulations. The regulations writing process for the production tax change has been extraordinarily interactive with the taxpayers, incorporating their input in all phases of development. Although this process may have slowed the pace of development, it resulted in more clarity in a complex set of regulations. The regulations writing process continues to date.

The change to a production tax on net profits also posed challenges for the audit staff in the areas of hiring qualified auditors and training auditors for the new demands of the position. The department has had difficulties attracting qualified auditors under the state pay schedule. New and expanded credit programs have also added to their workload. Despite these challenges, the audit staff has completed most of the audits under the PPT system.

The greatest difficulties faced by the department since the implementation of a net profits production tax system are the collection, use, and storage of the huge amounts of data received monthly and annually. As an example, the department receives monthly information from each active oil and gas company regarding the amount of oil and gas produced, the amount spent in operating and capital expenditures, the amount of credits earned and used, and the payment submitted. The department also receives documents pertaining to petroleum sales and netback calculations, most of which are submitted in Adobe Acrobat pdf format, which is not a suitable format for data storage or use. Assembling this data in a useable format is time-intensive and subject to error, as the data are cut and pasted into spreadsheets manually. Further compilations and changes subject the data to additional error and distortion.

The department's access to and use of this important data would be substantially improved if the information were housed in a central database, with access provided to all users of the data. The department believes securing a database will assist in operating more efficiently and effectively as an interface with both taxpayers and the public.

Conclusions and Recommendations

A government's fiscal regime is just one element for oil and gas companies to consider when weighing options for where to invest. Many other elements, such as resource risk, political risk, environmental factors, and availability of labor and equipment, also play a part in companies' decisions about where to invest. It is very difficult to separate these factors in order to determine the extent to which a government's fiscal system influences investment choices.

While it is untenable to blame a tax system for the lack of industry investment, it is equally untenable to claim that the tax system is the reason increased activity or investment occurs. The past three years have seen dramatic swings in oil prices from a high of \$134 per barrel to a low of \$38 per barrel just 6 months later. An economic recession stifled investment and business activity in the United States and much of the developed world for over a year. The economic activity of the past three years may not have been the best benchmark by which to judge the impact of a tax system.

Nevertheless, it is prudent for state officials to monitor praise for and criticisms of its fiscal systems from both industry and the general population that they serve. High oil prices of recent years have swelled state bank accounts and some have suggested that the state is in the best financial position since statehood. Business periodicals and industry journals report that state is benefitting at the expense of a single industry – petroleum – and that the tax rate under ACES is too high and “takes away the upside” for the oil and gas producers. Criticism is often centered around the marginal tax rate under ACES, under which the government share of each additional dollar of profit may be as high as 93%.

State officials also make efforts to stay informed on the global oil and gas markets and opportunities in other jurisdictions, including how Alaska ranks competitively against them. Among the recent events in government taxation was the royalty modification undertaken by the Canadian province of Alberta. Studies conducted for the Alberta government showed that the royalty changes made in 2007, combined with the recession, the changes in natural gas markets, and other jurisdictions' efforts to attract investment, were making Alberta less competitive for limited petroleum investment

capital. The government responded to this information by changing its royalty structure in a way that the government's share of oil and gas profits would be lower.

The State of Alaska depends heavily on the oil industry, with more than 80% of its unrestricted revenue coming from oil taxes and royalties. State officials should continue to monitor the state's competitiveness in oil and gas opportunities, and be prepared to modify it as the need arises.

8.

FAST Study
October 2010

STATE OF ALASKA

Department of Revenue



Comprehensive Plan and Feasibility Study

Alaska Department of Revenue Tax Division
RFP Number 2010-0400-9618

Executive Summary

Needs Assessment

The Alaska Department of Revenue's Tax Division (DOR/TAX) relies on a patchwork of 17 automated systems and over 100 manual "side-systems" to administer 22 tax programs.

- DOR/TAX manages over **\$3 billion in Oil and Gas Tax revenue** using an eclectic mix of home-grown side-systems that include multiple databases and unsecured, unstable spreadsheets stretched well beyond their intended use. Storing sensitive taxpayer information in these databases and spreadsheets poses a high security risk.
- The 17 systems used to administer different taxes and functions have been pieced together over the past 15+ years without integration or an overall architecture. The systems do not scale to meet current needs and are inflexible and difficult to maintain. Since the initial development of the systems, many tax laws have changed and the systems have not changed accordingly.
- DOR/TAX constructed the current tax systems as silos of information pertinent to only the tax types they serve. This makes sharing data with other tax systems difficult, requiring customized interfaces, or manual processes. It also makes the business processes that have grown up around the systems duplicative and inefficient, and, in many cases, business processes which should be standard across tax types conflict between systems.
- The vast majority of the agency's business processes are manual. Many exist strictly to get information from one system, database, or spreadsheet to another or to reconcile information. The prevalence of manual processes significantly increases the probability of human error. DOR/TAX also uses manual processes for fundamental business purposes – for example, distributing shared taxes of over **\$44 million to 124 communities** throughout Alaska in 2009.
- DOR/TAX employees spend a higher proportion of their time compiling, organizing, and reconciling data than actually auditing, examining, analyzing, forecasting, or managing tax programs.
- The limitations and inflexibility of existing systems impose a burden on taxpayers. Current reporting processes are inefficient and ineffective, and create unnecessary work and cost. As one taxpayer stated, "the Tax Division's inefficiency makes taxpayer interaction with the division inefficient."
- DOR/TAX cannot easily produce reports required by the legislature and policy makers because the current systems prevent timely, complete, and correct extraction of data. Reports can be inaccurate and misleading due to incorrect and incomplete data and human error.
- Because of the changing nature of the economy, Alaska may, in the future, need to adjust its state tax structure away from such a heavy reliance on Oil and Gas Taxes. The current capabilities of DOR/TAX make analysis of new opportunities, or investigation of competing alternatives, nearly impossible. Economic research capabilities of the current system rely on manual processes.

DOR/TAX Vision

DOR/TAX's vision is to "Efficiently use resources to promote compliance and fairly collect and accurately report the State's revenues." The DOR/TAX management team believes the single, most significant step it can take to achieve its vision is to procure and implement a modern integrated tax management system (ITMS).

ITMS implementations are complicated, high-risk projects. An effective mitigation strategy needs to focus on three key elements:

- Choosing a sound implementation approach
- Using an effective procurement process to select a strong solution and trusted business partner
- Carefully planning and managing the project to ensure successful delivery

Implementation Approach

Options available to states desiring to implement a modern, ITMS include the following.

- *Custom systems:* For many years, custom-built mainframe-based systems were the only option available to state revenue agencies. They remain an option today. A custom solution can provide a high degree of flexibility, especially if the agency is very satisfied with its existing business processes and does not want to adapt them to other solutions. Custom systems, however, pose a higher degree of implementation risk and, historically, have been a more costly option.
- *Transfer systems:* Transfer systems were a popular option from the mid-80s through to the early 2000s, offering the advantages of lower cost and lower risk. At least two vendors marketed and implemented transfer solutions. To our knowledge, there are no vendors actively marketing transfer system solutions for an ITMS in the US market today.
- *Commercial off-the-shelf (COTS) systems:* COTS solutions became an option for state tax agencies after the turn of the 21st century. They offer advantages of lower risk, reduced cost, and quicker deployment of proven "out-of-the-box" functionality. Today, there are at least five companies with COTS solution offerings for the US market.

Since 2000, COTS solutions have become the predominant option for an ITMS in state revenue agencies within the US. In the past decade, 21 out of 27 ITMS contract awards were for COTS solutions. In the past five years, 12 of 14 contract awards were for COTS solutions and two followed a custom approach.

DOR/TAX does not have to decide on the implementation approach at this time. DOR/TAX can construct the Request for Proposal to allow vendors to propose an ITMS using the vendor's desired approach. This technique encourages competition and allows DOR/TAX to select the system, and the approach, during the evaluation of bidders that best meets the needs of DOR/TAX.

Scope

The scope for an ITMS includes:

- Replacing all 17 official systems, various FoxPro and MS Access databases, and over 100 Excel spreadsheets in side-systems with one integrated system. Current legacy systems will be retired as the tax types they administer are integrated into the new system
- Migrating all 22 tax types to a new, ITMS
- Cleaning data and preparing data for conversion from existing legacy systems
- Training users and operators to fully utilize system functionality
- Implementing new e-filing opportunities for taxpayers, including Modernized e-File (MeF)
- Increasing compliance functions thereby enhancing non-filer, collections, and audit functionality
- Automating distribution of shared taxes after user approval
- Configuration meeting the State of Alaska and DOR's specific requirements and providing the ability to quickly adapt the tax types to the State's ever-changing tax laws and regulations
- Providing for data warehouse and integrated imaging capabilities
- Implementing streamlined business process changes to improve efficiency and effectiveness

Costs

While the number of taxpayers in a jurisdiction has some bearing on costs, the complexity of the taxes, desired functionality, and the number of tax programs are much more significant factors. A high volume of taxpayers can affect software and hardware scalability and performance, but the functionality needed to process and administer a tax is not materially affected by a large or small number of taxpayers.

A budget for an integrated tax system for a five year period is estimated to be \$30 to \$35 million, and DOR/TAX is requesting a budget of \$35 million. This budget should be sufficient to attract a number of vendors offering a range of solutions to respond to an RFP, and it is within the industry standard range.

<i>Estimated Project Costs—Five Year Period</i>		
Component	Amount – Low (millions)	Amount – High (millions)
Vendor Software and Services	\$23.0	\$27.0
Hardware	\$1.375	\$1.375
Project Operating Expenses	\$1.325	\$1.325
Maintenance and Support (2 years)	\$4.0	\$5.0
Total	\$29.7	\$34.7

For an ITMS project, one of the critical risk factors is inadequate funding. It is important to set a realistic level of funding, allowing multiple vendors to bid thereby providing competitively priced proposals for goods and services. Setting a budget too low may result in getting a system that does not meet the agency's needs. A jurisdiction also runs the risk of limiting the number of vendors that respond to an RFP or receiving attractively priced responses that carry high business and delivery risks.

Benefits

Benefits achievable through a modern ITMS align with DOR/TAX's vision. In many states, revenue collections resulting from increased compliance exceed the amount spent on a new ITMS within 2 or 3 years after implementation is complete.

Benefits of a modern ITMS include the following:

- *Improving efficiency* - by facilitating a consistency of operations across all tax types and functions and enabling the automation of high volume, routine tasks. An ITMS project will streamline business processes and align them with best practices while at the same time providing a means and a method to incorporate tax law changes rapidly and easily.
- *Promoting compliance* - through enhanced voluntary compliance as well as collection, audit, and discovery activities. An ITMS will make conducting business with DOR/TAX simpler and easier for taxpayers and enable DOR/TAX to provide taxpayers with accurate and complete information. It will also enhance collection management tools.
- *Increasing fairness* – everyone is paying the taxes they are legally required to pay. An ITMS will allow DOR/TAX to systematically identify and act on taxpayers who fail to file, improve audit selection, identify potential underreporting, and discover taxpayers that should be registered and paying taxes, but are not.
- *Accurate reporting* - through an ITMS that provides consistency of information across all tax types and functions. An ITMS will provide real-time access and query capability, and enhanced flexible reporting capabilities.

An ITMS also streamlines system maintenance by providing a single system with a common architecture and standard delivery platform.

Implementation Roadmap

- This study provides an implementation roadmap, offering DOR/TAX practical guidance as it prepares for procurement and plans for implementation of an ITMS. Key activities include:
- Preparing for procurement – activities before the RFP is issued
- Writing the RFP
- Preparing for the project with an emphasis on project management, change management, communication management, risk management, data preparation, and deciding on project location

Factors Leading to Success

In our experience, there are certain contributing factors that can greatly influence a project's outcome. Those that are within the influence of DOR/TAX are described in detail and fall within leadership support, staffing support, logistic support, and leadership support.

Summary

It is evident from the research, reviews, interviews, and analysis of the information there is a clear need for implementation of an ITMS in DOR/TAX. It is only through extensive and redundant data manipulation, the use of unsafe side-systems, and numerous hours spent cross checking and re-keying data that DOR/TAX is able to sustain the level of service they provide now.

I. Table of Contents

Executive Summary.....	ii
I. Table of Contents.....	vii
II. Introduction	9
A. Background	9
B. Purpose and Scope.....	9
C. Methodology.....	10
III. DOR/TAX Mission and Vision	11
A. External Stakeholder Input	11
B. DOR/TAX's Mission and Vision.....	12
C. Strategic Actions and Approach.....	12
IV. Gap Analysis: "As Is" and "To Be"	14
A. Inventory of Existing Systems	14
B. Gap Analysis - Current vs. Future Business Processes	28
C. External Stakeholder Input	46
V. Integrated Tax Management System Project	56
A. Project Vision Statement	56
B. Goals and Objectives.....	57
C. Critical Risk Factors	57
D. Alternative Approaches	59
VI. Costs and Benefits.....	68
A. Cost Components.....	68
B. Pricing Strategy for DOR/TAX.....	70
C. Integrated Tax Management System Budget	70
D. Comparison Information from Other States.....	72
E. Integrated Tax Management System Project Benefits	78
F. Benefits Realized in Other States.....	84
G. Funding Alternatives	85
VII. Implementation Roadmap.....	88

A.	Preparing for Procurement: Activities Before the RFP Is Issued.....	88
B.	Writing the RFP	90
C.	Alternate Method	96
D.	Preparing for the Project	96
VIII.	Project Management Plan	99
A.	Integration Management.....	99
B.	Scope Management	103
C.	Time Management.....	107
D.	Cost Management.....	108
E.	Quality Management	108
F.	Human Resources Management.....	109
G.	Communication Management	111
H.	Risk Management	111
I.	Implementation: Factors Leading to Success	114
IX.	References	117
	APPENDIX A – Stakeholder Interview Participants	118
	APPENDIX B – External Stakeholder Interview Questions	119
	APPENDIX C – Mission and Vision External Feedback	120
	APPENDIX E – High-Level Diagrams	123
	APPENDIX F – Acronym Glossary	160

II. Introduction

A. Background

For the past three years, the Alaska Department of Revenue's Tax Division has been investigating options to replace its patchwork of systems, databases, and spreadsheets that currently support the processing and collection of taxes. The agency staff and external consultants have prepared numerous analyses, studies, and documents to determine needs, identify options, and recommend the best approach for the Tax Division's future.

In July 2010, Alaska Department of Revenue's Tax Division (for the purposes of this report, DOR/TAX) issued a Request for Proposal (RFP) soliciting proposals for an unbiased study to determine the feasibility, scope, and estimated costs of a new Integrated Tax Management System (ITMS) to streamline revenue administration. Fast Enterprises, LLC (FAST) of Greenwood Village, Colorado was awarded the contract to perform this study. This report is one of the deliverables required of that contract.

B. Purpose and Scope

FAST worked with DOR/TAX to develop the scope of this study. The purpose of the study is to identify technology solutions supporting the overall vision of DOR/TAX.

The scope includes:

- Obtaining external stakeholder feedback, both to help DOR/TAX make sure its vision and mission are centered on the outcomes valued by stakeholders and to identify ways the agency can improve tax administration and the services it provides
- Assessing the gap between DOR/TAX's current state and its desired future state through a detailed technical, functional, and business process analysis
- Making recommendations on feasibility and scope, validating costs, and identifying benefits associated with an ITMS
- Identifying technical, business, and delivery risks, along with an implementation approach to minimize those risks
- Providing DOR/TAX with a roadmap based on practical guidance as it prepares for the procurement and plans for implementation of an ITMS

C. Methodology

FAST employed the five methods described below to perform this study.

1. External Stakeholder Interviews

DOR/TAX helped identify external stakeholders including a mix of taxpayers, association representatives, legislators and legislative staff, state agency personnel, and a local government representative. Twenty individuals participated in 14 interview sessions conducted in person and by telephone. Interviewees answered a consistent set of questions designed to obtain feedback about DOR/TAX and to provide input regarding the agency's vision and mission, ways to improve tax administration, and services delivered by the agency. Appendix A contains a list of stakeholder interview participants.

2. Gap Analysis

DOR/TAX's subject matter experts (SME) participated in 22 sessions to gather information about current systems and business processes. The sessions were organized by functional area. Participants discussed system constraints, limitations, desirable features, and functionality to increase effectiveness, streamline business processes, and improve productivity.

3. Management Team Workshops

Two sessions with DOR/TAX management reviewed and refined the agency's mission and vision statement and aligned its technology strategy with this vision. Stakeholder feedback and input was shared with the management team during the second session.

4. State Surveys

FAST reviewed and analyzed information previously collected by DOR/TAX about project costs, schedules, and user satisfaction and supplemented it with additional survey information about project scope, costs, and benefits.

5. Review of Prior Reports and Analysis

FAST reviewed many reports, studies, and analyses provided by DOR/TAX, including the following:

- Oil and Gas Tax System: Preliminary Requirements (October 18, 2007)
- Oil and Gas Tax System: Solutions Analysis (October 18, 2007)
- Oil and Gas Tax System: COTS Solutions Analysis (January 28, 2008)
- Tax Revenue and Information Management System: Implementation Strategy (TRIMS) (October 13, 2009)
- Commercial Off-the-Shelf (COTS) Revenue Management System: The Future of Revenue Administration (September 2008)
- New Tax Revenue Management System: Project Charter (August 27, 2008)

III. DOR/TAX Mission and Vision

A clear statement of an organization's mission and vision is important to provide clarity of focus, both for employees working inside the organization and for those affected externally by the organization's day-to-day operations. A carefully-crafted statement is able to communicate an organization's core purpose and focus, and express its aspirations for the future. It also forms the foundation for a strategic approach that can position the organization to reach its goals.¹

A. External Stakeholder Input

DOR/TAX desired contributions from external stakeholders to serve as an input for this study, and to provide validation prior to an annual review of its vision and mission statements. FAST interviewed 20 stakeholders including taxpayers, association representatives, legislators and legislative staff, state agency personnel, and a local government representative.

After sharing a copy of the previous mission and vision statements, the questions posed to stakeholders were:

- What is your general reaction to DOR/TAX's mission and vision?
- Is it appropriate?
- Does it look like they're focusing on the right things?
- Is anything missing?

Feedback centered on the four topics discussed in more detail below.

Clarity – Stakeholders noted the statements were “quite a blend of things” and that DOR/TAX could “tighten up their focus with fewer statements.”

Compliance and Collections – The most frequent comment throughout all the interviews stressed placing an emphasis on compliance rather than increasing revenue collections. One stakeholder explained,

“Shouldn't [the Tax Division] just be trying to collect the correct amount that is due? Increasing compliance makes sense, but simply *increasing revenue collection* sounds like they're only out for money – even if taxpayers are already paying what they owe.”

“It's good they want to focus on efficiency because the Tax Division's inefficiency makes taxpayer interaction with the division inefficient.”

¹ The mission and vision statement shared with stakeholders can be found in Appendix C, along with the more detailed feedback shared with DOR/TAX.

Another observed,

“Trying to move the compliance needle closer to 100% is important. But simply *increasing revenue* seems to communicate the wrong message.”

Efficiency – Several stakeholders noted the importance of operating efficiently. One stakeholder said, “It’s good they want to focus on efficiency because the Tax Division’s inefficiency makes taxpayer interaction with the division inefficient.”

Wise Use of Resources, Technology – There was a concern that emphasizing the maximum use of technology, sent the wrong message. One stakeholder commented, “The important thing is to use technology wisely and effectively.”

Another explained,

“It’s not about arbitrarily using technology to the max – you use technology to improve customer service or increase the public’s confidence in the Tax Division. Technology is a means to achieve the Division’s goals.”

Stakeholders also provided feedback on DOR/TAX’s mission. DOR/TAX is not able to change its mission statement without approval of the Office of Management and Budget since mission statements are used to succinctly describe an agency’s objectives.

B. DOR/TAX’s Mission and Vision

Mission – Collect taxes, inform stakeholders, and regulate charitable gaming.

Vision – Efficiently use resources to promote compliance and fairly collect and accurately report the State’s revenues.

C. Strategic Actions and Approach

To make significant progress in reaching its vision, DOR/TAX requires a strategic approach that addresses the fundamental tools at its disposal – people, processes, and technology. The DOR/TAX management team believes the single biggest barrier it faces today is its patchwork of aging, inflexible systems and, in some cases, the absence of any system to support tax administration. By necessity, manual processes are pervasive in the agency’s operations, consuming its peoples’ time and energy that should be focused on compliance and taxpayer service activities. The accurate collection and reporting of revenues is at risk by insecure side-systems and extensive reliance on manual processes.

An ITMS would help DOR/TAX achieve its vision by providing a state-of-the-art platform able to leverage technology in the future. Benefits achievable through a modern ITMS align with the components of DOR/TAX’s vision.

Efficiency - by facilitating a consistency of operations across all tax types and functions and enabling the automation of high volume, routine tasks. An implementation project will streamline business processes and align them with best practices.

Promoting compliance - through enhanced voluntary compliance as well as collection, audit, and discovery activities. An ITMS will make conducting business with DOR/TAX simpler and easier for taxpayers and enable DOR/TAX to provide taxpayers with accurate and complete information. It will also enhance compliance by providing collection management tools.

Fairly collect - by making sure everyone is paying their fair share of taxes, allowing DOR/TAX to systematically identify and act on taxpayers who fail to file, improving audit selection, identifying potential underreporting, and helping discover taxpayers that should be registered and paying taxes, but are not.

Accurately report - through an ITMS that provides consistency of information across all tax types and functions with real-time access and query capability, and enhanced, flexible reporting capabilities.

With the exception of cash processing and booking liabilities, there is not an automated system to administer the state's Oil and Gas Production Tax.

All other processes for this tax type are performed manually.

IV. Gap Analysis: “As Is” and “To Be”

The gap analysis presented in this section results from DOR/TAX’s current state as compared to the desired future state made possible with the procurement and implementation of an ITMS. The current state is determined through a variety of means including an inventory of DOR/TAX’s existing systems, examining current functionality and business processes, and through interviews with external stakeholders. Limitations, constraints, and problems are identified and compared to the opportunities for improvement inherent in a modern ITMS.

A. Inventory of Existing Systems

DOR/TAX has 17 systems used to administer different aspects of its tax types and over 100 MS Excel spreadsheets that track information the systems do not capture. Since the initial development of the systems, many tax laws have changed and the systems have not changed accordingly. It is important to note that with the exception of cash processing and booking liabilities there is not an automated system to administer the state’s oil and gas production tax. All other processes for this tax type are performed manually.

The current systems are difficult to modify and maintain and do not scale to meet current needs. The result is the creation of quasi-official “side-systems.” Side-systems most often take the form of MS Excel

spreadsheets and, in some cases, MS Access databases that are external to systems consistent with DOR’s designated *Application Development Platform and Database Standard*.

TAX has 17 systems used to administer different aspects of its tax programs and over 100 MS Excel spreadsheets that track information the systems do not capture.

Well intentioned users create side-systems out of necessity to capture information needed to perform their jobs. Storing information in side-systems results in many problems including data duplication, inconsistent data, incomplete data, and loss of data. Additionally, side-systems introduce serious security risks.

Presented below is an inventory of the 17 systems

DOR/TAX maintains and uses to perform their assigned duties. The tables below include important information as to the age of the system, if known, why the system does not meet the needs of DOR/TAX, and obtainable functionality and benefits if DOR/TAX replaces them with an ITMS.

1. PowerBuilder Applications

The Alaska IT Group (2008) concluded the tax applications built in PowerBuilder are not SOA standard (p. 3). The same study found the core infrastructure of the existing PowerBuilder solution to be

incomplete and lacking many features that would streamline and consolidate the business practices of DOR/TAX. A few of those features include non-filer identification, collections management tools, audit management tools, and refund tracking. PowerBuilder applications are not consistent with DOR's designated *Application Development Platform and Database Standard*.

Cash Processing System (CPS)	
Age	14 years
Purpose	• Used by the Accounting and Collections Department to process, verify, track and post payments for all tax and license types • Interfaces to TAS to apply payments to taxpayer account and liability
Limitation/Problem	• Important information not available, such as payment directions • Not all payments made to DOR can be reported on from CPS • CPS data must be combined with TAS data to create a full report • Certain payment information is only accessible by the Accounting and Collections Unit
An ITMS could	• Standardize payment functionality - view, direct, re-direct, reverse, allocate, and otherwise associate payments with accounts and taxpayers • Make finding and understanding payment information more straightforward and visible to users talking with taxpayers and solving complicated tax payment related issues • Provide complete payment information - including split payment directions, history of allocations, and automated bad check fee application • Automate tracking and reporting of payments • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

Tax Processing System (TAS)	
Age	15 years
Purpose	• Acts as the accounting backbone for almost all tax types – Except Oil and Gas Property – only Oil and Gas Tax payments appear in TAS • Used by almost all DOR/TAX users to research and apply payments • Tracks Cigarette Consumption liabilities • Manages Mining License, Electric, and Telephone Cooperative Taxes • Manages all Gaming Tax and License functions • Holds keyed refunds information
Limitation/Problem	• Does not include management of Oil and Gas Property Tax • Difficult to change and understand code • Return details separate from transaction details • Transaction sequence numbers hard to decipher • Hard to track down the return adjustment and tie the adjustment to resulting transaction • Assessment reports to taxpayers sometimes report incorrect information causing confusion and frustration • Audit assessment reports sometimes have to be posted by IT staff due to system anomalies and inconsistencies in TAS • Changes on account status must be done manually
An ITMS could	• Include detail information for Oil and Gas Property Tax • Allow ability to view all taxpayer financial information in one place • Allow communication with taxpayers about their total liability • Allow automatic offsets to other periods/accounts • Allow revenue distributions performed in-system • Provide refund and refund interest tracking mechanisms • Provide audit and collections assessments • Provide standardization and automatic billing • Allow automatic calculation of all types of interest • Allow audit adjustments to be made from an audit case • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries • Allow for improved management tracking and system functions

Data Entry and Examination Excise (DEE)	
Age	8 years
Purpose	• Data entry and examination functionality for returns from Tobacco, Alcoholic Beverage, Fisheries, Commercial Passenger Vessel, Large Passenger Vessel Gaming, Tire Fee, Vehicle Rental, and Motor Fuel Claim for Refund
Limitation/Problem	• Originally developed as a training tool • Never designed for use in a production environment • Difficult to improve and correct • Only used to capture Oil and Gas Production Tax payments and liabilities
An ITMS could	• Integrate data entry and examination process into the same system as the financial information - no data transfer between DOR/TAX systems • Allow configurable rules for taxpayer and account information and return line items - the system can easily be modified to meet changing needs • Provide version control allowing users to make adjustments to the same copy of the return while keeping a history of who and when the changes were made • Allow for viewing/adjusting of amendments against original return • Allow management and control of workflow • Allow measurement and adjustment of line item rules to detect and deter fraud, improve processes, improve forms design • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

Data Entry and Examination (DEE) Motor Fuel/Corporate Income	
Age	12 years (Motor Fuel); 10 years (Corporate Income Tax)
Purpose	Serves as the data entry and examination system for Motor Fuels and Corporate Income Taxes
Limitation/Problem	- Originally a transfer solution from Wyoming's Mineral Tax System - Programming guidelines were not always followed, creating a system both difficult to maintain, but also incapable of keeping up with the State's needs and legislation - Cannot change the line items on the return to adapt to legislation changes - Difficult to make adjustments to return values - sometimes have to create and re-key all information from the return to make the adjustment - Does not meet DOR/TAX's needs
An ITMS could	- Integrate data entry and examination process into the same system as the financial information - no data transfer between DOR/TAX systems - Allow configurable rules for taxpayer and account information and return line items - the system can be easily modified to meet changing needs - Provide version control allowing users to make adjustments to the same copy of the return while keeping a history of who and when the changes were made - Allow for viewing or adjusting of amendments against original return - Allow management and control of workflow - Allow measurement and adjustment of line item rules to detect and deter fraud, improve processes, and improve forms design - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

Alaskan Salmon Price Report (ASPR)	
Age	Unknown
Purpose	• Supports data entry and management for Fisheries Business Tax filers • Gathers information needed for public reports
Limitation/Problem	• Complicated for users to extract data from the system in desired formats
An ITMS could	• Allow viewing and reporting needs for this data from a standard template • Allow for scheduled reporting and automated transmission of reports through email, FTP, or other methods • Allow easy data comparison to other information in the system • Allow for forecasting and data analysis on the reported data • Allow for historical reporting and storage of previous reports • Allow for ad hoc query analysis and "on-the-spot" answers
Fish and Game Licensing Application	
Age	Unknown
Purpose	• Tracks the approval process and the license status for Fish and Game Licensing
Limitation/Problem	• Difficulty tracking if a taxpayer is in compliance, holding a current license when they file their returns - compliance data matching is difficult to perform and time consuming • Gaming licenses, returns, and stamp information reside in three different systems making it difficult to verify manufacturer licenses
An ITMS could	• Situations of concern could be automatically detected and flagged for user review and suspend or stop automatic processes from occurring if a taxpayer is not in compliance • Ability to check returns filed without a license and vice versa • Allow easy data comparison to other information in the system • Allow for forecasting and data analysis on the reported data • Allow for historical reporting and storage of previous reports • Allow for ad hoc query analysis and "on-the-spot" answers

Interest Engine for TAS	
Age	Unknown
Purpose	Calculates the interest of debt owed to DOR/TAX
Limitation/Problem	- Cannot automatically calculate interest on credits, refunds, assessments, appeals, or collection cases - Users typically verify calculation provided by TAS in an MS Excel spreadsheet and in other interest calculation software
An ITMS could	- Streamline interest calculations for all functions in the system - interest automatically calculated within the system based on configurable rules - Ability to manually add interest, if needed - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries
Unclaimed Property (UP) Viewer	
Age	Unknown
Purpose	View images associated with submissions in the UP system
Limitation/Problem	PowerBuilder does not meet state of Alaska IT standards
An ITMS could	- Provide ability to associate images with taxpayer, accounts, and refunds - Allow easy data comparison to other information in the system - Allow for on-line notifications and claims for UP to clear out backlogs and reduce inventory of unclaimed property - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries
Travel Documents Image Viewer	
Age	Unknown
Purpose	Assists DOR/TAX's Administrative Unit by archiving travel documents
Limitation/Problem	Does not include active travel documents
An ITMS could	Associate travel documents with system users, however, travel documents are normally handled by a State's Human Resources Division enterprise resource planning system and images are better integrated with internal business functions not related to taxpayers

2. Microsoft (MS) Access Application

MS Access is a program used by DOR/TAX with the State of Alaska's IT standards and is not consistent with DOR's designated *Application Development Platform and Database Standard*. There are many risks involved when using MS Access databases, including the lack of version control, history maintenance, and data integrity as well as a vulnerability to data corruption. Storing sensitive taxpayer information in these databases poses a high security risk.

Oil and Gas Production Tax	
Age	Unknown
Purpose	Tracks Oil and Gas credits and Joint Venture billing
Limitation/Problem	- In 2009, tracked Oil and Gas credits worth over \$310 million - Captures a lot of data - databases are currently exceeding 5GB and are difficult to access on user machines and to store/retrieve on network drives - Users accidentally override each other's data - Users make their own "copy" of the databases which are not updated when new information is added to the original database - High possibility of data corruption and loss of data - Provides low security control for data which contains sensitive taxpayer information
An ITMS could	- Provide a system architecture designed to handle large amounts of data - Provide version control to prevent loss of information - Provide one source of data available to all users - Prevent data from being lost and overridden - Provide for implementation security standards - Provide ability to capture and report on all data submitted by the taxpayer - Allow standardization of data submission - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

3. Web Applications

DOR/TAX has implemented three web applications which have expanded taxpayer self-service. Taxpayers now have the ability to file returns and license renewals, make payments, and submit additional information to DOR/TAX. The applications automate the receipt of information, so the staff does not have to enter the original data.

Unfortunately, the web applications reside on the same servers as the Permanent Fund Division's applications. DOR/TAX cannot make major changes between December and May due to the potential negative impact to the Permanent Fund Dividend applications.

The web applications built originally to allow the taxpayers to apply for licenses now perform additional functions. Since the initial implementation, the scope expanded to allow the web applications to accept return filings, payments, and additional information required from taxpayers. The applications stretch to provide accepting MS Excel spreadsheets for online filing, data submissions for the Economic Research Unit, and for providing information to the public. Unfortunately, the structure of the web applications lacks two important factors of good software, flexibility and scalability. When changes to existing services are required or taxpayers request new services the effort to perform those tasks is often excessive.

Online Tax Information System (OTIS)	
Age	3 years
Purpose	• Taxpayers use OTIS to submit tax returns and supporting information, make payments, and review a history of online transactions
Limitation/Problem	• Shares the same server as PFD – no changes between December and May • Online system was originally designed for part of the current functions - the system is not scalable to further additions and changes • For some tax types, the web application allows users to provide information in any format they would like which creates additional work for DOR/TAX to sort and standardize received data into a consistent format for analysis
An ITMS could	• Place online support for tax types on its own server allowing controlled changes as needed • Streamline and standardize data input to decrease taxpayer error • Streamline formats accepted from taxpayers to reduce workload • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

Online Permit and License (OPAL)	
Age	3 years
Purpose	• Taxpayers use OPAL to apply for licenses needed to conduct business and make payments for those licenses • Manufacturers and distributors use OPAL to fulfill requirements of filing monthly reports identifying pull-tab games and stamps
Limitation/Problem	• Shares the same server as PFD – no changes between December and May • Online system was originally designed for part of the current functions - the system is not scalable to additions and changes • For some tax types the web application allows users to provide information in any format they would like to, which creates additional work for DOR/TAX to sort and standardize received data into a consistent format for analysis
An ITMS could	• Place online support for tax types on its own server allowing controlled changes as needed • Streamline and standardize data input to decrease taxpayer • Streamline formats accepted from taxpayers to reduce workload • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries
Public Reports and Queries - Online	
Age	Unknown
Purpose	• Used to obtain information on Alcoholic Beverage Licenses, Fisheries Business License, Gaming Distributors, Gaming Manufacturers, Gaming MBP, Gaming Operator, Gaming Permittee, Motor Fuel Qualified Dealer License, Municipalities Electing to Defer Motor Fuel Tax, Tobacco Approved for Sale and Importation and Tobacco Dealer License Query
Limitation/Problem	• Shares the same server as PFD – no changes between December and May • Only queries information in TAS – information residing in other systems and on Excel spreadsheets is not queried making most reports incomplete and inaccurate
An ITMS could	• Place online support for tax types on its own server allowing controlled changes as needed • Information and communications with taxpayers could be expanded with the possibility for two way communications allowing for web messaging and problem resolution with full tracking and history • Place all information in same database for complete and accurate reporting

4. Visual Studio C# Client Applications

Through careful design, implementation, testing, and deployment of applications, Visual Studio helps build very secure applications. The security technologies provided by .NET, the operating system, and web browsers are available to secure applications. The three applications below do not suffer from security concerns, but they do present more of a maintenance issue because they exist on a different platform from all other applications maintained by DOR/TAX. Integrating these applications onto one platform with other DOR/TAX applications would also reduce redundant data and the need to learn multiple systems.

Offtake Volume Reporting (OVR)	
Age	Unknown
Purpose	- Tracks well head production data submitted to DOR/TAX by Oil and Gas Production taxpayers - Provides Economic Research Unit with data for analysis and forecasting
Limitation/Problem	- Amount of data captured is limited because it requires manual entry into the OVR system - data may be contained in other systems - Time consuming for users to review and search for needed information
An ITMS could	- Allow information currently captured in separate systems or spreadsheets to be included in reports for OVR - Allow upload of EDI information provided to DNR to streamline filing Oil and Gas Royalty Reports and reduce taxpayer burden - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries
Economic Monthly Report (EMR)	
Age	Unknown
Purpose	Provides information for forecasting models used by the Legislature and Governor's office
Limitation/Problem	Users must manually gather information, key and format it into MS Excel spreadsheets, upload it to EMR, and export into economic models
An ITMS could	- Streamline process by eliminating the need to gather data through separate methods and manipulating it outside the system - Use standard reporting tools to easily manipulate data - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

Gaming Stamp Manager	
Age	New
Purpose	Tracks Gaming Tax pull-tab stamps from the time they are ordered by DOR/TAX through the time the game is played
Limitation/Problem	- Does not provide the ability for operators, permittees, or multiple beneficiary permittees (MBP) to file online - Cannot access this information from a taxpayer's Gaming Tax account - Allows duplicate pull-tab numbers to be entered
An ITMS could	- Expand the process to enable operators, MBP, and permittees filing information to be captured along with other information currently captured in one system - All information pertaining to a Gaming Tax account would be accessible from a single location within the system - Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

5. Visual FoxPro Application

Visual FoxPro is a program used by DOR/TAX that does not comply with the State of Alaska's IT standards and is not consistent with DOR's designated *Application Development Platform and Database Standard*. There are many risks involved when using FoxPro databases, including the lack of version control, history maintenance, and data integrity as well as a vulnerability to data corruption. Application security when using Visual FoxPro is entirely dependent on locking users out of the application. Storing sensitive taxpayer information in these databases poses a high security risk.

Petroleum Property Tax	
Age	Over 10 years
Purpose	Assists in the generation of Oil and Gas Property Tax assessments
Limitation/Problem	- In 2009, over \$81 million in assessments processed through this application - Functionality similar to that of an MS Excel spreadsheet – users perform primarily work manually - Incomplete – lacking 40% of intended functionality - No IT staff experienced in Visual FoxPro - Minimal system documentation
An ITMS could	- Automate the assessment process using configurable rules designated by the users, statutes, and regulations - Include all needed functionality

	• One system platform to maintain for IT staff • Allow input information to be available in multiple formats for reporting, analysis, and ad hoc queries

6. Side-systems

Information that cannot be captured, manipulated, or compiled in the above systems is managed and maintained in MS Excel spreadsheets, referred to as “side-systems.” The functionality utilized in MS Excel ranges from simple data capture of information to advanced manipulation of data exported from within the systems for reporting and tracking purposes.

There are risks involved when using MS Excel spreadsheets for DOR/TAX data. The data may contain sensitive taxpayer information which a spreadsheet cannot adequately secure. Manual capture and manipulation of data presents a high-risk of user error. There is no version control in spreadsheets and a risk of users overwriting each other's work if they are using the same spreadsheets.

In the article “Porting Mission-Critical Excel Workbooks to Web Applications,” Mercer (2009) describes succinctly the issue DOR/TAX is experiencing today in the following paragraph:

“Simply put, Excel is not the appropriate solution for reliable, efficient storage and processing of large amounts of data and it lacks the stability to do this in a safe way. If a user's machine were to lock up during a 20 minute long file opening procedure or aggregate calculation, this could mean the permanent destruction of said spreadsheet due to file corruption. Also, because these files often sit on users personal hard drives and not on managed servers, they often fall outside the net of the IT department's automated backup routines” (p. 3).

This same article makes mention of the limitations of integration for the future when using MS Excel by saying:

“Excel is an application that plays very well with others. It will accept data in a number of different formats and convert that data to a spreadsheet format and vice versa. Because of these capabilities, many users often turn excel into a conduit for systems integration by using it to take data from certain systems, reformatting it and shipping it off to other systems. Although this is a perfectly acceptable use of Excel's capabilities, it is not a reliable long term systems integration strategy. This is especially true for mission critical systems, for which integrations will often require more advanced features such as record locking, batched transactions with rollback, message queuing, event logging, and scheduled processes” (Mercer, 2009, p. 4).

DOR/TAX pushes the use of MS Excel beyond Microsoft's intended use of the program and is using the program as a long term data storage tool because DOR/TAX does not have other tools available. There are better alternatives for mission-critical programs than relying on MS Excel workbooks within the marketplace. Mercer (2009) summarizes that by implementing one of those alternatives, “The gains in security, stability, and productivity are far from being negligible” (p. 5).

Two areas where MS Excel is the only tool available to management are: Revenue Sharing and Cigarette Tax Stamps Inventory Management.

DOR/TAX calculates Revenue Sharing (**\$44 million** in 2009) by retrieving information from the main DOR/TAX database using Sybase InfoMaker queries. The Accounting and Collections Manager compiles bulk data into an MS Excel spreadsheet and manipulates the data to calculate the revenue sharing distributions. This complex process could be incorporated and automatically calculated within an ITMS. The system can populate revenue models, create online analytical processing (OLAP) cubes, and produce standard reports from integrated templates for review by the accounting staff before funds clear for distribution.

The Cigarette Tax Stamp Inventory which generates **\$63 million** annually relies completely on MS Excel spreadsheets. An ITMS that includes an inventory module would provide tracking of inventory for comparison with returns information for better compliance.

7. Key Findings

To finance all state government operations, Alaska depends primarily on petroleum revenues. DOR/TAX manages the **\$3 billion** Oil and Gas Production and Oil and Gas Property Tax programs using an eclectic mix of authorized and home-grown side-systems. These two programs rely heavily on unsecured, unstable MS Excel spreadsheets even though these programs bring in over **77% of all tax revenues**. MS Excel provides for management of return data and is the source of information for Oil and Gas Taxes. FoxPro and some very basic TAS functions supplement the MS Excel spreadsheets. Risks presented by relying on MS Excel and other side-systems for managing these critical revenue programs raises great concern within DOR/TAX.

DOR/TAX constructed the current tax systems as silos of information pertinent to only the tax types they serve because of needs during the time of tax implementation. There does not appear to be an overall architecture plan to the creation of the systems. The current systems make sharing data with other tax systems difficult, requiring custom interfaces or manual processes. DOR/TAX efficiencies are hampered

“...use of Excel’s capabilities...it is not a reliable long term systems integration strategy.”

and revenue dollars due the State may remain uncollected since taxpayer and tax data cannot be automatically compared across the different tax types.

Tax systems that are designed as silos tend to enable the creation of business processes and rules that are “siloeed.”

Processes that could be the same across the organization are not because they were developed by tax type rather than function. An ITMS would lend itself toward unified business rules and processes, thereby improving operational efficiencies.

B. Gap Analysis - Current vs. Future Business Processes

FAST examined DOR/TAX's current systems and evaluated the current processes. Below is an outline of each of the major processes, including Imaging and Archive, Entity, Returns, Taxpayer Accounting, Payments, Collections, Audit, Appeals, Refunds, Security, and Reporting as they are now, followed by an analysis of what is offered in a standard ITMS. The *Gap* section for each functional area compares the current and future states. Please refer to the business process flow diagrams contained in Appendix E for additional information.

1. Imaging and Archive

a) Current Tax System

DOR/TAX currently images returns, payments, and taxpayer correspondence. The only audit documents imaged are the Oil and Gas Corporate Income Tax documents. Return imaging occurs at different times in the returns handling process depending on the return type. For example, DOR/TAX images Corporate Income Tax returns before examination, whereas they image Charitable Gaming returns after examination. After imaging, paper copies of the documents are gathered and archived.

Main tasks performed in the imaging and archive processes include:

- Generating and printing sheet separators
- Reviewing images and making corrections to them
- Routing paper return documents to different units depending on type and status of the return
- Generating and printing box count sheets for archive boxes
- Obtaining approval from Records Officer to have box of documents archived
- Distributing archive box inventory lists

b) ITMS

An ITMS can provide easy access to images from within the application, providing side-by-side views of the data and the image. Captured images of filed returns can be displayed beside the data input screens, facilitating the data entry of return information. Rules can be set so the system will change focus and zoom in on different segments of the images as data entry operators complete the sections of the online data entry form. In some cases, the electronic copy of the document can replace the paper copy, alleviating the need to archive paper copies of documents.

Integrated imaging provides the following abilities:

- Rotate and correct images
- Create correspondence in the system rather creating, printing, and then imaging it
- Add notes to the image or annotate sections of the image
- Track image details such as date imaged, sequence number, and who imaged the document

An ITMS provides the capability to index images on-line individually or in bulk. DOR/TAX can apply an index to an image captured at the front end of processing, in a standardized process, in many ways to support their processing requirements. For example, DOR/TAX may wish to index an image by:

- Taxpayer
- Account
- Period
- Return
- Payment
- Collections case
- Audit case
- Other cases such as registrations and appeals

c) Gap

One major disadvantage to the current system is the lack of image support for all tax types. Currently, no image support exists for the tax types responsible for bringing in the most revenue to the state: Oil and Gas Production and Oil and Gas Property. Additionally, DOR/TAX does not have the capacity at this time to image Tobacco Licenses, Personal Consumption Cigarette Tax documents, or documents from Appeals. Implementing an imaging process to image documents as they come in the door would provide standardization and tracking of documents received by DOR/TAX.

2. Entity

a) Current Tax System

For the majority of tax types administered by DOR/TAX, the entity must first exist in TAS before any processing can begin. A taxpayer can register through DOR/TAX's online filing program, OTIS, or can send in a paper registration form to be keyed by someone in DOR/TAX. A taxpayer record can have multiple accounts/licenses, each with their own addresses. Even though the taxpayer can have multiple addresses, the Corporation Income Tax account address is selected by the TAS system as the default. An account has the ability to have both a Legal and DBA (Doing Business As) name.

It is difficult to edit taxpayer identification numbers. The tax agent must create a new entity and have the Accounting and Collections Unit transfer the correct returns and payments to the new entity or request the IT Unit make corrections behind the scenes. There is currently no way to validate or standardize addresses keyed by the taxpayer in OTIS, or when keyed directly into TAS. It is very difficult to track all entity and account data for reporting.

b) ITMS

An ITMS allows for consolidated taxpayer information where all attributes and account information for an entity can be accessed from one location.

Identities - An identity is a string of characters used to identify either a taxpayer or an account. An ITMS can automatically assign a unique taxpayer identification number and account identifier to all taxpayers and accounts, respectively. Multiple identities may be recorded for a taxpayer and are the most efficient means of searching for and locating either a taxpayer or an account. Identities for a taxpayer

can be maintained both at the taxpayer level and the account level. Taxpayer identities can be set to be masked for security purposes if required. Changes to identities and multiple identity types are often supported and available for use on correspondence as part of configuration.

Addresses - A taxpayer may have one or more addresses of various types (for example, location address or mailing address). All addresses for a taxpayer can easily be maintained from the taxpayer level, including military and foreign (non-US). In addition, taxpayers may have the same address type at different levels of their account, for example a mailing address can exist at the taxpayer level, and a different mailing address can be active for a specific tax account. The address type can be considered when issuing correspondence. Addresses are commence/cease dated, allowing the system to record official changes. An ITMS can also be interfaced with or include National Change of Address certification to provide for change of address information. Addresses entered can be verified using USPS Coding Accuracy Support System (CASS) to ensure the addresses entered are deliverable addresses.

Taxpayer and Account Creation - In an ITMS a taxpayer can be created with a submitted return, a taxpayer can register through on-line filing, or paper documents can be received and keyed for taxpayer creation. For Corporate Income Tax, the Modernized e-File (MeF) process can provide enough information to create a taxpayer if one does not exist.

In addition, an ITMS also provides the following capabilities:

- Configure multiple name, address, and contact types for each taxpayer and account
- View history of changes made to names, addresses, IDs, and contacts
- Allow correspondence to be mailed to different names and addresses based on the type of correspondence
- Configure site-specific attributes for each account and taxpayer type
- Associate related entities such as corporation to subsidiary corporation
- Provide easy access from accounts to the associated licenses
- Provide communication through flags or notes attached at various levels

Some tax types have no system at all, including the Oil and Gas Production Tax which brings in over \$3 billion to the state annually.

c) Gap

An ITMS allows for consolidated taxpayer information with access to all attributes and account information from one location. Using CASS-certified address validation would allow DOR/TAX to receive a discount on postage and would lower the amount of correspondence returned due to invalid addresses. The ability to store multiple addresses, both at a taxpayer level and an account/license level,

and easily select (or let the system choose) the most appropriate address for certain types of correspondence reduces taxpayer confusion and time spent on taxpayer service.

Additionally, an ITMS provides the capability to present a taxpayer financial summary at a glance, view the entire taxpayer and all associated accounts, communicate between units within DOR/TAX about the taxpayer's status or account activity.

3. Returns

a) Current Tax System

Returns processing and examination is currently handled in multiple systems. Some tax types have no system at all, including the Oil and Gas Production Tax which brings in over **\$3 billion** to the state annually.

The current return processes:

- Require keeping the return and payment together until the 3-day payment process is complete - examiners do not have access to the return during this time.
- Cannot store all of the required information from returns needed for reporting and analysis.
- Requires re-keying a substantial part of the return multiple times when making an adjustment to a return in the DEE systems.
- Legislative changes cannot be made to the Motor Fuels or Corporate Income Tax system without breaking the system, so new requirements are pushed into side-systems for implementation.
- Put imaging the return at the end of the process, meaning agents are working off of paper returns that can be easily misplaced or lost.
- Require a "Red Sheet" to be filled out for amended mining returns that gives instructions to the IT staff to correct the system behind the scenes.
- Require some returns go through system checks to look for problems; return stops for manual review on problem identification. Many of these checks are no longer necessary, but DOR/TAX cannot change the system to remove the invalid edit checks.
- Once DOR/TAX corrects a return, the taxpayer should receive the corrected information. Unfortunately, the information sent to the taxpayer cannot always be explained by DOR/TAX.
- Data Entry staff keys Oil and Gas Corporate Returns as Corporate Income Tax returns then users convert them back to Oil and Gas Corporate returns; if returns are misidentified then the funds show up in the wrong accounts receivable account.

b) ITMS

An ITMS provides a platform for easily adding and changing return rules and formats. If DOR/TAX determines new reporting requirements, or other conditions change which require new return formats, a modern ITMS allows the update of the return to capture and report on the additional information.

An ITMS provides the capability to:

- Easily configure return error rules for each return type – not just tax type.
- Easily configure fields and schedules for capture after satisfying validation and calculation rules.
- Display fields in the system like they appear on the paper return.
- Generate work tasks and easily assign and track returns that need correction or review.
- Easily change or edit information on a return once entered in the system.
- Log changes to the return, display changed field values, and provide an audit trail of who made the change and when it was changed.
- Allow users to easily amended returns within the application and show all versions of the return.
- Redirect a return (and/or payment) incorrectly applied to the taxpayer, account, or filing period without re-keying it.
- Receive the taxpayer's Federal return information with the state return through the standardized MeF program.
- Configure multiple file formats for taxpayers to provide return information in bulk - XML, import from MS Excel EDI, flat file, through FTP, web filing, or other electronic means.
- Easily track, identify, and action taxpayers with gap periods or non-filed returns.

c) Gap

The current tax systems present multiple procedures that perform, essentially, the same task. An ITMS can, at minimum, simplify and standardize the returns examination process resulting in fewer training hours, better taxpayer service, and faster turnaround time. An ITMS can gather processing statistics to analyze and tune return rules. DOR/TAX can then stop returns that need review and set tolerances to process automatically those that do not. Modern systems allow you to easily adapt to changing forms then capture and report on data from all schedules of a tax return. MeF capabilities allow DOR/TAX to obtain a taxpayer's federal return and the state return through a standard interface thereby requiring the taxpayer to file only once for both requirements. Amended returns could simply overlay the original and the system can calculate and adjust amounts to repost instead of having the examiner re-key the entire return for amended posting.

Legislative changes cannot be made to the Motor Fuels or Corporate Income Tax system without breaking the system, so new requirements are pushed into side-systems for implementation.

In addition to standardizing the returns workflow, an ITMS can present multiple tools to more efficiently manage that workflow. Reporting tools indicate how many returns are currently waiting for review and how many returns stop for each of the different, configurable, return suspension reasons. Reporting tools can also provide statistics on user efficiency including the number of returns worked and the dollar amount of adjustments made. These reports can range from a simple list in the system to automated emails of formal reports when a work list hits above a certain threshold.

4. Taxpayer Accounting

a) Current Tax System

In the current systems, all taxpayer accounting functions are performed manually and are primarily handled by the Accounting and Collections Unit. DOR/TAX performs many of the unit's calculations outside of the system using numerous Excel spreadsheets. DOR/TAX creates assessment letters manually using either a MS Word or MS Excel template. Sybase InfoMaker queries provide the basis for the distribution of shared taxes to municipalities and other stakeholders when the Accounting and Collections Manager manually embeds the results in Excel templates.

The main tasks performed by DOR/TAX include:

- Preparing and sending out bills to the taxpayer
- Sending copies of bills to imaging to attach to the taxpayer's account
- Performing adjustments and abatements
- Performing offsets of credits between tax periods and tax accounts
- Calculating penalties and interest including all refund interest
- Preparing and verifying distributions of shared taxes
- Working with IT to correct taxpayer records directly in the database when the current user interface prevents updates

b) ITMS

An ITMS can automate many of the manual processes currently done by the Accounting and Collections Unit.

An ITMS provides the capability to:

- Automatically generate assessment letters based upon a schedule and data contained in the system paying special attention to flags and other account attributes.
- Automatically calculate and apply consistently and fairly all penalties and interest based on configurable rules determined by DOR/TAX.
- Forecast penalty and interest amounts if DOR/TAX applied a hypothetical payment to an existing debt at a future date. Forecast payment plans and pay agreements.

- Provide a central location for all taxpayer information including taxpayer correspondence, assessment or credit changes, and notes clarifying the reasons for certain actions.
- Store “up-to-the-minute” information on all transactions and track revenue from a taxpayer’s account to aggregate funds and funds to subsidiary general ledger accounts.
- Report balances of accounts receivables, payables, funds, and ledger accounts.
- Distribute revenue quickly, accurately, and automatically based upon configuration rules verified by examining pre-distribution information in reports, OLAP cubes, and queries.
- Generate a file processed by AKSAS to update automatically the general ledger for shared taxes fund accounting and subsidiary general ledger accounts adjustments.
- Create revenue models for forecasting, analysis, and economic research.
- Configure tax rates for each tax type, special rate periods for special circumstances, and court-ordered bankruptcy tax rates all through the on-line interface.
- Automatically offset debt on other accounts and periods based on rules determined by DOR/TAX – offsets can occur before billing or refunds to prevent sending out funds and then requesting the funds back from taxpayers.
- Offset refunds between taxes or intercept refunds (or PFD funds) automatically to pay liabilities.
- Adjust transactions with all transactions linked to the source transaction. Examples of adjustments include waivers, write-offs, protests, and petitions for relief.
- Reverse transactions that completely reverse a particular transaction from an account. The reversal transaction is associated with the original transaction to record the action. System can maintain history and provide who and when information for all transactions.
- Maintain filing periods and associate period attributes to taxpayers’ accounts. Attributes provide the source for business rule configuration in returns or selection data for reports.
- Validate write-offs and write-off debts in bulk to retire uncollectable debts.
- Track offsetting credits and debits, adjust small balances, split transactions, and process external transactions.
- Participate in the IRS Corporate Taxpayer Offset Program that allows state agencies to intercept federal income tax refunds and apply them to delinquent state tax debt.

c) Gap

Alaska citizens from 5 municipalities, 13 boroughs, and 106 cities benefit from an accurate and correct distribution of the shared taxes managed DOR/TAX. Manual actions are responsible for ensuring DOR/TAX distributed shared taxes of over **\$44 million**, to 124 communities throughout Alaska in 2009 (*Shared Taxes and Fees*, 2009). The current systems available to DOR/TAX offer only 48% of the capabilities available in a modern ITMS; only 3% of these take advantage of automation. Reducing tedious manual processes should allow for greater oversight and validation to ensure DOR/TAX distributes these critical funds accurately and efficiently.

In the current systems, DOR/TAX only sends bills when they first establish delinquency (excluding various collections notices discussed in the *Collections* section). Evidence from other jurisdictions indicates that the process of sending out a monthly bill increases revenue collection simply by keeping the debt fresh in the mind of the taxpayer - most taxpayers pay their bills when they receive reminders to pay, and when it is made easy for them. As an example, shortly after implementing their ITMS, the state of Montana saw a 39% increase in collections attributed, in part, to automatically sending account statements every month.

A full-featured ITMS provides a rich suite of functionality to maintain and report on taxpayer financial activity individually or en masse. By employing an ITMS, DOR/TAX could provide a better picture of the state of revenue with less manual effort and more precision.

5. Payments

a) *Current Tax System*

DOR/TAX accepts payments received through the mail, from walk-ins, from wire transfers, and from web applications. DOR/TAX follows different procedures for handling payments depending on whether they accept the payment in Juneau or Anchorage. There are four different internal applications, one external bank application, and many Excel spreadsheets used to track and process payment information.

The main payment tasks performed by DOR/TAX include:

- Manually keying payment information into CPS
- Reviewing the payment information in CPS - validated by three different people, by manually handling multiple documents
- Researching and applying payment information in TAS - often having to rely solely on the Accounting and Collections Unit for payment information
- Allocating single payments across multiple tax periods
- Depositing domestic checks to the bank through software provided by the bank
- Researching and analyzing accounts to figure out the amount of debt that should be credited

b) *ITMS*

An ITMS would streamline and simplify payment processing and maintenance. It would accept payments from all sources then use one system to process them. All payment information in the system would be accessible to all users with the proper security permissions. Information about payments entered into the system is available for reporting through numerous methods.

An ITMS provides the capability to:

- Secure payments manipulation to only users who should be able to make changes to the payments, but allow all users to view the payment information.

- Provide pending payments functionality to hold a payment until receipt of a return or posting of an audit, then automatically apply the payment upon receipt.
- Allow multiple payment types for more accurate payment application and better reporting
- Receive payment batches from multiple external sources for uploading payment information including electronic funds transfer, e-check, remittance processing, and credit card payments.
- Apply and direct payments to taxpayer accounts automatically. Allow payments to be split to different periods or accounts, either manually or automatically, according to configurable pay-off rules.
- Create payment batches on-line to process in the same manner as payment batches that are received from remittance processing machines. The same controls including batch validation are applied to batches processed using this function.
- Validate payment batches to ensure the batch has not yet processed, the batch is from a recognized data source, and the header information is consistent with the detail records
- Generate work tasks for batches and payments that cannot be processed automatically - queuing them for assignment, expedient tracking, correction, and resolution of issues
- Reverse a payment with a configurable reason to facilitate reporting and additional processing and then in the same transaction reverse all associated applicable transactions sourced from the payment
- Handle non-sufficient fund checks and notice of change files from banking institutions to debit taxpayer's accounts in order to recharge fees, add penalties, and reestablish tax liabilities as necessary
- Search for payment batches and individual payments using combinations of known information (e.g., check number, bank information, receipt date ranges, amount, or transaction number)
- Create processing documents to direct the payments not included in batches to multiple directions as necessary
- Track taxpayer banking information from checks received for payments
- Process ACH and IAT payments initiated by the taxpayer to debit the taxpayer's bank account
- Process change and correction files to update existing bank account information in the system or determine if specific ACH or IAT payments failed

c) Gap

Accepting payments is a critical part of any revenue agency. Currently all payments must be manually applied against a debt. An ITMS can automate this process. An ITMS can automate splitting a tax payment across multiple tax periods as well as multiple tax accounts. Payments can process differently depending on the payment source, e.g., a payment coming in without a return can hold waiting for a return, or a payment coming in with a bill can post immediately. DOR/TAX can report on different payment types separately or account for them differently. For example, DOR/TAX can designate a payment type to post to the Constitutional Budget Reserve Fund.

In the current systems, DOR/TAX only sends bills when they first establish delinquency (excluding various collections notices discussed in the *Collections* section). Evidence from other jurisdictions indicates that the process of sending out a monthly bill increases revenue collection simply by keeping the debt fresh in the mind of the taxpayer - most taxpayers pay their bills when they receive reminders to pay, and when it is made easy for them. As an example, shortly after implementing their ITMS, the state of Montana saw a 39% increase in collections attributed, in part, to automatically sending account statements every month.

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- Allow multiple payment types for more accurate payment application and better reporting
- Receive payment batches from multiple external sources for uploading payment information including electronic funds transfer, e-check, remittance processing, and credit card payments.
- Apply and direct payments to taxpayer accounts automatically. Allow payments to be split to different periods or accounts, either manually or automatically, according to configurable pay-off rules.
- Create payment batches on-line to process in the same manner as payment batches that are received from remittance processing machines. The same controls including batch validation are applied to batches processed using this function.
- Validate payment batches to ensure the batch has not yet processed, the batch is from a recognized data source, and the header information is consistent with the detail records
- Generate work tasks for batches and payments that cannot be processed automatically - queuing them for assignment, expedient tracking, correction, and resolution of issues
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Accepting payments is a critical part of any revenue agency. Currently all payments must be manually applied against a debt. An ITMS can automate this process. An ITMS can automate splitting a tax payment across multiple tax periods as well as multiple tax accounts. Payments can process differently depending on the payment source, e.g., a payment coming in without a return can hold waiting for a return, or a payment coming in with a bill can post immediately. DOR/TAX can report on different payment types separately or account for them differently. For example, DOR/TAX can designate a payment type to post to the Constitutional Budget Reserve Fund.

DOR/TAX has provided many avenues for taxpayers to make payments. The current payment batch entry and validation principles should not be lost when implementing an ITMS but rather improved upon. Adding the functionality provided by an ITMS to the current processes would provide enhanced visibility, better reporting, and increased clarity for users working with taxpayer accounts.

6. Collections

a) Current Tax System

In the current systems, all collections processing is manual. A DOR/TAX technician identifies a potential collection case and forwards it to the collector either by email or on paper.

DOR/TAX performs the following tasks manually:

- Tracks all collections in MS Excel
- Creates and stores all correspondence on paper
- Tracks all collection staging dates in MS Excel
- Files and tracks all liens and levies in separate MS Excel spreadsheets from the collection case
- Creates and tracks all payment plan agreements on paper and in MS Excel
- Retrieves bankruptcy information from multiple sources even if not connected to a collection case

b) ITMS

An ITMS provides the capability to:

- Provide automatic collection creation and staging.
- Provide automatic detection of payments.
- Provide automatic issuance of correspondence.
- Provide system tracking of collection stage and status and predict next steps.
- Provide levy and lien filing and tracking tools to create, search for, view, add periods, set line stages, add lien letters, view lien histories, and perform lien extensions.
- Share lien information with outside agencies and release liens in en masse.
- Provide bankruptcy tools, including automatic notice of taxpayer bankruptcy, electronic claims creation, and special handling of bankruptcy accounts. Use Electronic Bankruptcy Notification (EBN) technology through a free service provided by the Bankruptcy Noticing Center which enables federal bankruptcy courts to send notices electronically instead of in paper form.
- Provide collections recovery tracking and reporting.
- Associate images, received correspondence, pictures, and evidence to collection cases.
- Provide workflow tracking, assignment, and reminders.
- Provide risk calculation to increase collections efficiency.
- Create correspondence within the system automatically or from user intervention.
- Provide communications and indication that an account is involved in collections.
- Track and report on collections activities and recoveries.

- Maintain payment agreements and enable forecasting of payoffs by installment amount, or frequency of payment, and then monitor the taxpayer activity to ensure the taxpayer honors the agreement according to configurable integration rules.
- Establish garnishments, add debt sources, correspond with garnishees, and add garnishment vouchers.

c) Gap

The current systems in place only provide 32% of the capabilities normally found in modern tax divisions and DOR/TAX must perform all of these functions manually. The manual actions ensure DOR/TAX collects approximately **\$12.7 million** in unpaid revenues each year.

The capabilities of an ITMS can reduce the reliance on many manual collections processes allowing collectors to focus on cases that are more difficult. Automating collections processes will increase efficiency which will in turn bring in more potential revenue to the state in a timelier manner. A modern ITMS should provide the ability to use accurate data to increase fairness in automated collections actions. The system should provide the ability to track the amount of money collected using each specific collections action, thereby allowing DOR/TAX to determine which actions to concentrate on for maximizing revenue collection.

Because the process is currently manual, it is not impossible to tell how much revenue goes uncollected or quantify current opportunities in this area. Experience in other jurisdictions does, however, provide proof that compliance increases when agencies establish regular and consistent billing and follow up with the taxpayer regularly soon after establishing the debt.

DOR/TAX may not need all of the tools described above immediately to follow up on existing collection cases. However in interviews with users, they frequently mentioned how upstream manual processes in other areas prevent the posting of returns and payments. When those areas become more efficient because of an ITMS, there may be more of a need to increase compliance efforts and for collectors to have the tools available to handle the increased workload.

7. Audit

a) Current Tax System

Note: When considering auditing, we make a distinction between auditing a return as it processes through the system and auditing a taxpayer's filing history after the returns post. The returns processes and procedures considered above cover the return reviews and individual return or desk audits. This section considers the field audit, normally performed at the taxpayer's location, conducted after receiving more information than provided on the returns.

Audit selection: In the current systems, there are several ways to determine which accounts to audit. Some units select audits based on a specific credit, some work off an audit plan, and others leave audit

selection to an auditor's discretion. One constant across all tax types is that the auditing process is manual.

The main audit tasks performed by DOR/TAX include:

- Identifying which taxpayers to audit
- Contacting taxpayers
- Creating correspondence using MS Word
- Determining audit findings using MS Excel
- Tracking statutes of limitation using MS Excel using a different spreadsheet
- Tracking outstanding audits and audit stages using an MS Excel tracking spreadsheet
- Preparing Audit Adjustment Reports and Tax Adjustment Reports using MS Word
- Keying audit data into the appropriate system to post audit

b) ITMS

An ITMS can automate many of the above processes as well as provide extra functionality to make the entire audit process more efficient and fair.

An ITMS provides the capability to:

- Manage audits in progress and report on audit recovery results.
- Manage audit details, track the statute of limitations, consider transactions in previous periods, view previous audit information for the taxpayer, and report on audit sources.
- Create and maintain work papers that contain detailed or summary information prepared in the system or imported from other sources.
- Import previous return history automatically into work papers reducing audit preparation time and manual re-keying of returns used in the audit.
- Create templates for work papers to allow the auditor to store the data, statistical information, and calculations that result in audit findings and adjustments. The work papers may be complex, taking into account external audit data, or a simple recording of findings from an external audit mechanism.
- Configure and track work papers to share between tax types or unique to each tax type.
- Configure multiple layers for review of work papers and/or the entire audit to allow for peer and manager concurrence and approval while providing status tracking.
- Use timekeeping tools to help auditors track and report their time spent on the audit or in audit-associated training, office processes, or other related time.
- Manage reporting tools for audit selection basing the decision on internal data, previous audit data, external data, warehouse data, or other sources.
- Automatically create audit adjustment reports based on information in the work papers.
- Allow auditors to work from anywhere using downloaded information, remote connection, or standalone capability.

- Automatically issue correspondence based on audit selection or information stored in the audit record.
- Associate images, received correspondence, pictures, and evidence to audit cases.
- Provide workflow tracking, assignment, and reminders.
- Prevent or allow certain actions on a taxpayer's record while the audit is in progress or after an audit posts to a taxpayer's account.
- Lock payments received during the audit so the system applies the credit only to audit liabilities as instructed by the taxpayer.
- Provide for due process and retention of taxpayers' rights while ensuring audit details are available for review and the processing of appeals.
- Allow other users to identify when an account is under audit, who is performing the audit, and what periods are involved in the audit - even if they do not have the security to view any other audit details.

c) Gap

DOR/TAX audit coverage is limited because, in some units, auditors are so busy ensuring the input data is correct they never get time to perform audits. As other parts of an ITMS receive automation enhancements, auditing may become routine and auditors may have more time to perform audits to ensure compliance and increase taxpayer knowledge. When this happens, the current tools will be insufficient to ensure the selection for audit is fair and equitable. An ITMS can provide the necessary tools to perform audit selection fairly and conduct audits more efficiently. Reporting tools can base their inputs on work performed and allow managers to measure and monitor results and distribute the workload fairly to auditors. Improved data accessibility provided by an ITMS should help determine which accounts will make better audit candidates.

With increased efficiency in other functional areas and by using automated selection tools, DOR/TAX should be able to perform better audits and include additional compliance audits in their audit plans.

Compliance audits can bring in new, currently uncollected revenue. Timekeeping tools will help DOR/TAX track auditor actions, determine the most effective actions, and increase training or improve processes in areas that need attention. An ITMS will ultimately provide auditors with the capability to focus on auditing instead of spending their time "herding data" like they have to with their current systems.

8. Appeals

a) Current Tax System

The DOR/TAX Appeals Unit is currently responsible for processing between 50 and 100 appeals a year. Appeals information is stored and tracked externally using MS Excel spreadsheets until DOR/TAX reaches a decision. Users post all decisions manually to the system and make any adjustments manually.

The main tasks performed by DOR/TAX include:

- Receiving and processing requests for appeals
- Logging appeals into an MS Excel spreadsheet and tracking them
- Retrieving supporting documentation for appeal
- Maintaining correspondence and discussion with the taxpayer
- Interacting with other divisions to make sure inappropriate contact does not happen while the appeal is ongoing – for example, mailing collection letters to the taxpayer

b) ITMS

An ITMS has the ability to track and maintain appeal information during the appeal review rather than as an additional task in the appeal process. Tracking all appeal information in one system can consolidate appeal information, reducing the effort to collect appeal documents.

An ITMS provides the capability to:

- Secure appeal information to prevent unauthorized users from viewing and editing.
- Easily identify accounts involved in appeals to prevent inappropriate contact even for users without the security to view the appeal.
- Track appeals stages, statuses, decisions, and resolutions including who performed the tasks and when the tasks were completed.
- Link appeal cases to taxpayers based on the rules configured for a given appeal type. The case can stand independently and need not be associated with a particular taxpayer, account, or to the exact transaction under appeal.
- Define the business activity of processing an appeal including the configuration of steps, stages, decisions, and actions taken to perform the activity.
- Manage appeal documents, correspondence, and associated information.
- Stop certain automatic and manual processes during the processing of an appeal.
- Report aggregate or individual, historical, process, and procedural information resulting from appeals for business process improvement.
- Associate images, received correspondence, pictures, and evidence to appeal cases.
- Provide workflow tracking, assignment, and reminders.
- Report activities to higher appeal authorities with full disclosure of information from a central location within the system for cases that cannot receive resolution within DOR/TAX.

c) Gap

The biggest advantage an ITMS has over the existing system is the ability to identify which accounts or returns are currently in appeals. An appeal flag can prevent certain automated processes on an account. An example of this might be to stop collection activity for an account that is under appeal. An ITMS can also secure appeal information so that only those involved in the appeal can view and edit appeal information.

9. Refunds

a) Current Tax System

The refund issuance process involves many different people from the Accounting and Collections Unit as well as the appropriate tax type staff. DOR/TAX creates correspondence for refunds outside the system and spends time manually reviewing documentation and keying information into TAS, AKSAS, or an MS Excel spreadsheet. The only automated processes performed in AKSAS occur once DOR/TAX hands off the refund to the Treasury Division for issuance.

The main tasks performed by DOR/TAX include:

- Reviewing paper documentation for each refund request to verify that a refund or credit is available to issue.
- Using MS Excel spreadsheets to track refund details not tracked in the system such as refund status, issued date, and warrant number. DOR/TAX must update the spreadsheet multiple times throughout the refund process.
- Manually offsetting other debt owed prior to refund issuance.
- Manually calculating and applying any refund interest owed to the taxpayer.
- Manually entering information into AKSAS.
- Manually downloading information from AKSAS after a refund issuance to update the DOR Tax system.
- Mailing refunds to the taxpayer with supporting documentation if the refund amount is \$50,000 or more (the Treasury Division mails refunds under \$50,000 directly).

b) ITMS

An ITMS can ensure refunds are paid accurately and on time. It can automate many of the manual research processes currently performed and interface with external accounting systems, such as AKSAS, to provide quick and accurate turnaround to the taxpayer.

An ITMS provides the following capability to:

- Automatically create files to be processed by AKSAS rather than users re-keying information
- Automatically create refund requests based on configurable rules designated by DOR/TAX
- Configure refund review rules with separate rule set for different tax types
- Configure multi-level approval for refunds

- Send a refund out as either a paper check or direct deposit
- Add refund-level notes for additional documentation on an individual refund
- Automatically post of refund interest based on applicable rules
- Automatically offset debts on different accounts for the same taxpayer
- Secure refund approvals to only allow certain users to approve refunds
- Deter fraud by detecting the number of refund checks to the same address/bank account, stopping refunds for suspected fraudulent taxpayers, and alerting users to suspect activity

c) Gap

The current process for issuing refunds is manual and very inefficient. It involves moving paper and emailing between the source unit and Accounting and Collections Unit, sometimes multiple times for the same refund. It also involves manually calculating refund interest, offsetting money to other accounts on the taxpayer, and entering information into AKSAS. An ITMS can automate most of the current process as well as eliminate the need to track refunds in an external spreadsheet. Approvals can happen between different units, but issue research can happen within the system and each party involved can receive an alert when a refund-related action is necessary. Configurable refund interest and offsets rules can apply allowing automatic posting upon refund approval.

Refund information can pass back and forth between an ITMS and AKSAS automatically without human intervention. An ITMS provides a more efficient refunds process with less manual intervention, less manual calculations, and a quicker turnaround for the taxpayer.

One way to control fraud is through checks and balances integrated into an ITMS with change points only allowed through tracked and approved modifications.

Refund fraud is a big industry concern in tax departments at all levels of government. One way to control fraud is through checks and balances integrated into an ITMS with change points only allowed through tracked and approved modifications. The current system lacks these controls.

10. Security

a) Current Tax System

In the current tax systems, security is handled on two different levels. The first level of security consists of a user name and password to log into the system. The second level of security is a position-level security. Each user is assigned to a specific position in the system. Each position possesses different permissions to perform different actions. In addition to those, there are some exceptions where a

function is locked down to one or two users. In this case, permissions are usually hard-coded in the application.

b) ITMS

An ITMS will provide built-in security functionality for the application that is configurable, flexible, and easily changeable from within the application.

An ITMS provides the capability to:

- Secure different areas of the system using configuration.
- Secure individual links and buttons in each area using configuration - allowing separation of duties.
- View which taxpayers a user has visited and the actions performed on that taxpayer.
- Allow certain users to view information on certain taxpayers.
- Secure all information within the system.
- Add and edit users along with the roles assigned to them.
- Terminate a user's ability to access the system.
- Transfer one user's security settings to another.

c) Gap

An ITMS can provide more robust security and greater flexibility than the current systems. An ITMS puts all taxpayer data behind the same security wall to protect sensitive, confidential taxpayer data.

11. Reporting

a) Current Tax System

The current reporting capabilities are, for the most part, manual. There are some pre-defined reports that can be requested from the IT staff, but those rely on the information stored in one of the systems.

Often, all the information needed for a report is not captured in the systems but must be gathered from paper documents and MS Excel spreadsheets then combined with the information from the automated systems.

Limitations of the reporting processes include:

- Most reports are created through a very resource-intensive, manual process in which data must be gathered from multiple sources
- The DOR/TAX Annual Report takes five to six months to compile
- For requests from outside agencies, including the Legislature, tax agents must be taken away from their daily responsibilities to compile data from multiple sources, a process which can take anywhere from a day to a couple weeks

*The DOR/TAX Annual
Report takes five to six
months to compile.*

- Some data is not available, and some numbers are unreliable, making some requests for data impossible to fulfill
- Limited data is captured off the return making it necessary, at times, to locate all paper returns from multiple boxes currently in storage

b) ITMS

An ITMS can provide automated reporting capabilities that do not demand users' time allowing them to perform their assigned duties. Since an ITMS can easily be changed to capture additional or new information, those details can easily be incorporated into new reports.

An ITMS provides the capability to:

- Locate and associate data within the system
- Present data in multiple formats, lists, and formal reports and manipulate the way data is viewed
- Configure reports within the system
- Automatically generate reports - daily, weekly, monthly, annually, etc.
- Automatically deliver reports by email
- Generate reports in real-time
- Store generated reports for a designated period of time
- Generate a PDF version of a report
- Store all data in the same system

c) Gap

While DOR/TAX has some reporting capabilities, there is a large gap between the current process and what an ITMS can provide.

An ITMS equipped with robust reporting capabilities can alleviate the current reporting pains. With all data for all tax types in the same place, canned queries and reports can be developed for reports that need to be run on a consistent database. OLAP cubes can be used to pull in a large set of data and allow the user to manipulate that data until they get the information they need. Plain English querying tools can allow a user to write simple queries without a programming background. These tools can provide accurate numbers quickly, without the extraordinary effort currently required.

Limited data is captured off the return making it necessary, at times, to locate all paper returns from multiple boxes currently in storage.

C. External Stakeholder Input

1. Current State

Stakeholders were asked several questions to formulate external perceptions of the current state with respect to DOR/TAX. Specifically, stakeholders were asked about DOR/TAX's reputation and services they currently receive. In the context of providing information about improvements to tax administration and additional services they would like to see DOR/TAX provide, insight into the current operating environment was also obtained. This feedback is particularly useful in determining how the limitations of existing systems and business processes affect external stakeholders.

a) Tax Division's Reputation

Stakeholders were asked,

"Based on your interactions with the Tax Division, are there a few words that aptly describe their general reputation?"

By far, the most frequent response was, "responsive." It was noted that agency staff are "helpful, knowledgeable, and pay a high attention to detail." One observed, "The Tax Division has a great reputation for being helpful when taxpayers call," and another one said, "I rate them very high. They're accessible and provide good information. In one word, they're outstanding."

The professionalism of staff was specifically lauded. "They are professional and competent" and DOR/TAX is able to "hire good people and hold onto them." One stakeholder noted, "It's important that auditors understand good accounting principles, and Tax Division auditors do. That's not true with other agencies."

Several stakeholders mentioned the high caliber of employees in the economic section, calling them "competent," "respected," and "professional," capable of producing a "high quality product," even though they "occasionally struggle with their forecasts" and "have limited capabilities due to the limitations of the Tax Division's systems."

Personal characteristics mentioned in the interviews included "honesty" and "integrity." Several taxpayers noted that DOR/TAX seems to have a "very personal relationship with the taxpayer" and the "quality of the relationship is different – better – than in other jurisdictions." "The Tax Division has an open line of communication and I don't want to see that change. Their customer service is good – employees are friendly and helpful."

Although the number of stakeholders interviewed was small, two very different opinions emerged about audit staff's knowledge of the industries they are auditing. One taxpayer was very complimentary, "The Tax Division's people are more knowledgeable about the industry than most tax agencies. This helps them understand the context with which they're interpreting and applying regulations. It's clear the Tax Division values training and provides training to their employees – they don't outsource the training process to the company being audited."

Another taxpayer had a very different perspective,

“The Tax Division has lost a lot of expertise and they don’t appear to be training their new people about the industry. Companies shouldn’t have to provide industry training to auditors, although we’ve given them ample training sessions and tutorials. At some point, the Tax Division should be able to use this information to train their own people.”

While DOR/TAX was lauded by some as being a “good listener,” another noted, “they listen, but they don’t seem to hear what you’re saying. There are opportunities to interact, but sometimes you feel like you’re talking to a brick wall.” Similarly, one taxpayer felt as though DOR/TAX, “operates in a vacuum – they do things without involving us, without seeking our participation.” Another taxpayer felt, “they need more of a business acumen, more of a business sense.”

Two stakeholders described the DOR/TAX as “inflexible” and “rigid,” but one added, “...maybe that’s something you want in a tax agency.” The other was less forgiving, “I have found their views to be rigid, and they don’t try to understand your business. They don’t have the empathy you might expect.”

Numerous stakeholders noted DOR/TAX is “under resourced with technology” an observation confirmed in conversations with a DOR/TAX employee who revealed, “word is out – taxpayers know our systems are broken.”

Another stakeholder who was quite positive in their overall assessment of DOR/TAX noted, “On the negative side, if they don’t like something, they’ll write a regulation to get their way.” Yet another observed, “The Tax Division has good intentions, but they aren’t able to provide timely information for us regarding regulations and new legislation.”

One interviewee’s comments focused on taxpayer service,

“As a small business, knowing what we need for registration, forms, permits, etc. is hard, especially when you’re going through it for the first time. When I tried to find out what I needed, my interaction was cold. They should strive to be more business-friendly, more customer friendly.”

b) Current operating environment

Numerous stakeholders noted DOR/TAX is “under resourced with technology” an observation confirmed in conversations with a DOR/TAX employee who revealed, “word is out – taxpayers know our systems are broken.” One stakeholder commented, “You can’t call yourself professional if you don’t have a system that supports the efficient collection of data.”

“We file reports – but it’s not clear what they do with the information because when an auditor shows up, they ask for the same information again.”

By far, the most common and consistent message was directed to the limitations and inflexibility of existing systems that impose a burden on taxpayer reporting and severely limit information available to legislators, executive agencies, and local governments.

Taxpayers were vocal in expressing their concerns and complaints about the need for duplicative reporting and the way in which information is collected,

“Sometimes the same information needs to be reported three different ways for different systems and different sections. There is a high level of redundancy of reporting.”

“Taxpayers are asked to repeatedly provide the same information. If it was possible for systems to share data internally, they could avoid duplicative reporting by taxpayers.”

“The Tax Division doesn’t understand the needs of large taxpayers – they aren’t able to collect information in an efficient and effective manner. They ask for everything in an MS Excel spreadsheet but, as a large taxpayer, that simply doesn’t work. Their latest request is for a spreadsheet with 95 tabs. The Tax Division uses FoxPro, but FoxPro is outdated and needs to be replaced.”

“The Tax Division keeps asking for the same data in different ways and in different formats – auditors need it one way, economists need it another, etc. They should be able to put the data into one system and extract it for whoever needs it and for whatever purpose they need it. There has got to be a better way – and spreadsheets are not the answer. For a taxpayer to have to hire someone to input data into a spreadsheet is backwards and very inefficient. It creates a lot of unnecessary work and cost.”

“The current process is inefficient and ineffective. It requires taxpayers to provide the same information multiple times. It is clear Tax Division’s existing systems cannot organize and

retrieve information very well. When the agency needs information, they ask for it from the taxpayer rather than retrieving it from their systems. That seems very inefficient.”

“We file reports – but it’s not clear what they do with the information because when an auditor shows up, they ask for the same information again. Apparently, it’s easier for them to get the information from us than to retrieve it from their systems.”

While taxpayers find it difficult to report data, consumers of information including the legislature, executive branch agencies, and local governments commented on limitations on the information available to them. One stakeholder noted,

“With the new Oil and Gas Tax, it’s been a real struggle to get information from the Tax Division in any detail, especially for credits. We’d like to know answers to questions like how many taxpayers have applied, what is the revenue effect of each, and so on.”

The value of this type of information was reiterated by another stakeholder,

“We’re interested in getting more information about tax credits. There are a lot of them, and it would be nice to have more info – What are they? Who’s using them? How much do they cost? Are they working?”

Inflexibility in the way data is gathered and stored limits the ability to report information in ways stakeholders find would be useful. One stakeholder shared a specific example,

“We requested the agency to present revenue production by oil field. The response we received was that information is structured by company and not by geographical area.”

For purposes of accurate budgeting, one stakeholder emphasized the importance of the information provided by DOR/TAX,

“We want access to all the information we need to estimate revenues. We need a further break down of the information. They mean well and they’re getting closer, but they’re not there yet.”

Another stakeholder agreed,

“We would like to see information presented on more of a cash flow basis – currently we see revenue net of credits. We’d like to see the total value with amounts that break out the royalty values, the production base, and so on. That would give us a lot more information, both for forecasting and for policy purposes.”

Another topic that surfaced in stakeholder interviews was the timeliness of regulations and tax forms,

“The biggest issue is timeliness of regulations. It’s difficult to operate without regulations, instructions, and definitions – you’re not sure how to report and you can’t understand nuances.”

The lack of a stable Oil and Gas Tax return was also cited as a problem, "It is simply not clear what we're supposed to file."

While taxpayers were vocal in expressing the need for tax forms and more guidance, at least one stakeholder noted,

"The Legislature gave the Tax Division a huge job with the new Oil and Gas Tax, and the tax is incredibly complicated. Industry wants them to be done with their regulations already and companies want different interpretations. This is something the legislature is watching closely and they know it's a hard job. I'd say to the Tax Division, *don't lose focus.*"

One stakeholder also mentioned concerns with the audit process noting,

"Some audits take a long, long time. Difficulties getting interpretations make the process even more drawn out and complicated."

2. Future State

One of the most significant aspects of planning for the future is taking into consideration the needs of external stakeholders.

To obtain stakeholder input, two questions were posed to interviewees:

- In your opinion, is there anything DOR/TAX should be doing to improve tax administration? Are there areas that should receive additional attention and focus?
- Are there additional services you would like to see DOR/TAX provide?

Responses to these questions are organized and summarized based on the topics that were raised in interviews including: system improvements, reporting, and information sharing; electronic filing; taxpayer services; and other issues.

a) System Improvements, Reporting, and Information Sharing

Both taxpayers who are required to report data to DOR/TAX and stakeholders who rely on information from the agency cited the value of having a more modern and robust way to store and retrieve information. Taxpayers mentioned their desire to see an increase in the efficiency of their interactions with the agency,

"The Tax Division should be able to retrieve information from one system rather than require taxpayers to provide the same data many times."

"They need an automated system so they don't have to ask for the same information multiple times. Taxpayers should be able to provide data once, and the agency should be able to slice and dice it anyway they need to."

"They should be able to put the data into one system and extract it for whoever needs it and for whatever purpose they need it."

"The Tax Division needs a system that can organize and retrieve information while protecting and safeguarding confidential taxpayer information."

Taxpayers also mentioned the importance of consistency and predictability in their interactions with the agency, "We want a stable platform, not something that keeps changing all the time."

One important characteristic repeatedly mentioned by those who rely on information and reports from the agency is the need for flexibility,

"A nimble system would allow the Tax Division to be more responsive and not spend as much effort as they currently do producing information and reports."

"Flexibility is king. Quickly adapting to change is important for new revenue streams."

"Make changes easy to implement. If changes cannot be made quickly someone will make a 'side-system' to go around the automation. Necessity is the mother of invention. If the people maintaining the system cannot be responsive then someone will build a side-system."

"Alaska updates its technology very infrequently. The Tax Division will need to be able to adapt to the future – the possibility of new tax types or changes to current taxes. The legislature will make revisions to the Corporate Income Tax, mining taxes, and so on in the future. Flexibility is important along with the ability to work with new data. The more tools they have for analysis of data the better."

"The Tax Division needs a system that can organize and retrieve information while protecting and safeguarding confidential taxpayer information."

New ways of presenting information was also described as an important enhancement,

"As a big user of data, it would be nice to see the Tax Division move to more of an internet basis for reporting information rather than all paper and publications. I'd like to see more innovation in how information is displayed and communicated, along with the ability to slice and dice data so you can see details and trends."

"A lot of what we see is very static. You can't drill down into the data. The agency could do a better job of presenting data."

Some of the agencies that receive information from DOR/TAX including local government expressed a desire for more comprehensive data sharing agreements so they could access better and more complete information. It was also mentioned that it would be nice if the economic resources of the DOR/TAX

could be made more accessible to other agencies in government to increase the sophistication of analysis that is currently not possible.

b) Electronic Filing

Improvements in electronic filing were cited frequently as a means to improve tax administration,

“We work with many different jurisdictions and, in comparison, the Tax Division needs a better platform to ease electronic reporting. They don’t seem to benchmark with other jurisdictions to see how well they’re doing or how they can improve.”

“Our number one priority is EDI (*electronic data interchange*). Reporting on spreadsheets multiple times is frustrating and extremely inefficient.”

“I’d like to see a state-of-the-art online tax filing system that can minimize the time and effort it takes for taxpayers to file.”

While large taxpayers spoke of the need for EDI, the desires of smaller taxpayers were different. The need for simplified filing in general was stressed, of which electronic filing was an important part. Options currently exist and it was noted, “Their progress towards on-line filing is good” and “They’re more innovative than other departments when it comes to on-line filing and renewing permits.” One stakeholder stated,

“On-line filing for small taxpayers is a nice service. However, it should not be mandatory since not all small taxpayers have computers. Once it becomes mandatory, it stops being a service.”

The requirement to file the same information with different agencies was also noted.

“Much of the information filed is identical, but you have to complete two different forms for two different agencies. Isn’t there a way to complete one form that satisfies both agencies?”

“Because different agencies have different systems, you have to log on multiple times. It would be nice if all of your interactions with multiple agencies could be handled electronically in a single transaction. That seems to be the direction things are going.”

c) Taxpayer Service

A number of improvements in taxpayer services were mentioned, starting with a diligent push to make it as easy as possible to conduct business with DOR/TAX.

“They should work hard to make it easier to do business. Simplicity should be their focus. People don’t like paying taxes, and you should make it as simple as possible.”

When asked about new services, one stakeholder responded,

“I’m not as interested in new services as just trying to provide the right level of services. The Tax Division has regulations, but not at the level that would be useful.”

Another stakeholder made the same point,

“We would welcome timely, precise, and clear regulations together with the opportunity to provide feedback on proposed regulations and forms. The tax system should be self-administering – but it can’t be without timely, precise, and clear information for taxpayers.”

According to one interviewee, “Their goal should be that taxpayers have all the information they need.”

Access to regulations was also brought up as an important issue,

“It should be easier to access regulations – they need to be easily accessible, not just in a thick binder. Active taxpayer education is important.”

“Efficiency of customer service is something to work on. Excellent customer service is more than being nice. It means having all the information a taxpayer needs in one place so they don’t have to call back five times to get what they need.”

Several other ideas to improve tax administration were mentioned in various interviews,

“It’s important that people receive a notice and a reminder of what they should pay. People have so many different obligations, and notifications and reminders are very helpful.”

“As a taxpayer, it would be nice to be able to get a preliminary view/ruling regarding your filings. They offer that on an advisory basis, but it would be helpful to have something you can rely on.”

“My company is a big believer in statistical sampling. The Tax Division seems a little resistant. The agency should be using modern, valid techniques for sampling that, in turn, impose less of a burden on taxpayers.”

“There should be an easier way for innovative ideas (especially by small companies) to flourish without getting stifled by regulations. There is a need for more flexibility when it comes to the licensing of new products and process types.”

d) Other Issues

As interviewees talked about actions DOR/TAX could take to carry out its mission and vision, several discussion points surfaced,

“Maybe the agency is already doing this, but they should be working on and thinking about tax reform ideas for the future. Our revenues are trending down, so hopefully they’re thinking about sources and options other than oil and gas.”

“As tax administration issues bubble up, the Tax Division should be making the legislature aware of them. Their mission statement includes *informing stakeholders*. When issues come to the attention of the legislature, it means they didn’t get satisfaction from the Tax Division and it would be helpful if they could be more proactive in letting us know about those issues.”

“One big concern is if there are enough resources for audit, especially with the new tax regime. It’s important to make sure they have money for the auditors they need to make sure the state is not being cheated.”

e) Valuable Service to Maintain

Another question asked of stakeholders was,

“Are there valuable services the Tax Division provides that you want to make sure they continue providing in the future.”

Sometimes as organizations shift their attention to new challenges, they may overlook the importance of current activities that are valued by their stakeholders. This question was meant to help identify those types of valued services.

Responses to this question included the following,

“The Tax Division cannot be derailed from its primary mission which is compliance and the collection of tax dollars.”

“The Revenue Sources publication” and “Input for the 10-year forecast.”

“Accurate reporting including motor fuel data reporting.”

“They have open lines of communication, and they shouldn’t give that up. Customer service is pretty good – they’re responsive, friendly, and helpful, and that should not change.”

“The agency has a great web site and it’s easy to find information. They need to keep that up.”

“Their ability to provide good customer service to applicants and taxpayers is good; they answer phones quickly.”

“We wouldn’t want the Tax Division to change the quality of their relationship with us – they have a very personal relationship that is different than most agencies in other jurisdiction.”

“The most valuable service they provide today is communication and accessibility. The ability to call and talk to someone is great.”

“I’d like to see them continue holding workshops and meetings prior to adopting regulations. These allow dialog and opportunity to express opinions and concerns. This should be a standard of practice for any set of regulations they consider.”

“Providing rulings to taxpayers is an important service. The Tax Division does this today and, by law, they are advisory, not binding. While we would prefer binding rulings, we would not like to see agency give up this practice.”

“They do a fabulous job with charitable gaming. There are some complaints, but they have a solid set-up and I’d hate to see that change.”

3. Key Findings

One of DOR/TAX's key assets is their personnel; they have a reputation for being responsive, professional, and competent.

However, stakeholders know that DOR/TAX is "under-resourced with technology." Systems' limitations and inflexibility impose a burden on taxpayer reporting and severely limit information available to legislators, executive agencies, and local governments.

Taxpayers were vocal in expressing their concerns and complaints about the need for duplicative reporting and the way in which information is collected. Current reporting processes are inefficient and ineffective and create unnecessary work and cost for taxpayers.

Both taxpayers who are required to report data to DOR/TAX and stakeholders who rely on information from the agency cited the value of DOR/TAX having a more modern and robust way to store and retrieve information. Inflexibility in the way data is gathered and stored limits the ability to report information in ways stakeholders find is essential. Desirable system characteristics included flexibility and the capability to access and present information differently.

Improvements in electronic filing were cited frequently as a means to improve tax administration. For some large taxpayers, the number one priority was identified as EDI (*electronic data interchange*). For smaller taxpayers, the need for simplified filing in general was stressed, of which electronic filing is an important part.

Taxpayers expressed a strong desire for the right level of taxpayer services, making it as simple as possible to report and pay taxes. The importance of timely, precise, and clear information for taxpayers was emphasized along with taxpayer education and convenient access to regulations.

Systems' limitations and inflexibility impose a burden on taxpayer reporting and severely limit information available to legislators, executive agencies, and local governments.

V. Integrated Tax Management System Project

A. Project Vision Statement

DOR/TAX project envisions an ITMS with the following attributes:

“Comprehensive: incorporates all information and revenue management functions of the Tax Division;

Robust: requires minimal changes to program code as new tax types are implemented and existing tax types are changed; and

Integrated: includes information about all taxpayers that is accessible by all tax units and, through security controls, with other departments.

The desired solution will help the Tax Division enhance revenue collections via standardized user interfaces and processes, increased data accuracy and integrity, user-friendly reporting tools, automated prompts for staff to take action, and a case management system to streamline investigations” (State of Alaska Department of Revenue Tax Division [ADOR/TAX], 2009, pp. 2-3).

A new system will allow DOR/TAX to “spend *less* time on:

- Manual processes that are often duplicative
- Maintaining spreadsheets
- Maintaining files
- Tracking taxpayers
- Tracking deadlines
- Reconciling data currently in various separate databases
- Researching whether taxpayers filed and paid in a timely manner
- Generating routine correspondence and communication with taxpayers from scratch
- Working to develop management systems lacking in the current environment
- Writing and executing specialized queries for extracting data” (ADOR/TAX, 2009, p. 3)

A new system will enable DOR/TAX to “spend *more* time on:

- Core, mission-critical functions
- Audits
- Investigations
- Research and analysis
- Appeals
- Pursuing non-filers
- Collecting monies owed to the state
- Developing and enhancing core skills in staff

- Applying better information to improve taxpayer service
- Improving revenue forecasting models
- Managing workloads efficiently
- Developing procedures and desk manuals for business continuity” (ADOR/TAX, 2009, p. 3)

B. Goals and Objectives

ADOR/TAX (2009) states “the goals and objectives for an ITMS project might include the following:

- Provide comprehensive tax revenue and information functionality to improve the efficiency and effectiveness of overall tax administration processes.
- Meet time and budget constraints.
- Eliminate the need for paper-based processes through automated entry and workflow of documents such as tax returns and information report filings.
- Eliminate redundant data collection and storage systems throughout DOR/TAX.
- Reengineer existing processes to maximize human and system resources.
- Fully document all business processes and eliminate redundant processes.
- Increase staff efficiency and direct focus to their primary duties.
- Facilitate the accurate calculation of taxes by eliminating problems associated with error-prone data entry and inconsistent application of business rules due to manual processes.
- Provide staff with access to self-service information based on their roles.
- Provide taxpayers with the ability of ecommerce with a modernized and fully functional web portal.
- Provide appropriate security to meet the requirements of all Federal and State laws regarding confidentiality and security of personal information.
- Regardless of the implementation strategy chosen, ensure that the State owns and maintains its revenue management system with as minimal support as possible from outside vendors.
- Ensure that the system is expandable to meet the needs of future tax types using State IT resources to the maximum extent possible” (p. 4)

For a complete discussion of scope, please refer to *Scope Management* in section VII.

C. Critical Risk Factors

ITMS projects are complicated, high-risk projects. It is important to identify critical risk factors so that a strategic approach, effective procurement process, and a well thought out implementation plan are in place to maximize the opportunities for success.

The greatest overall risk to DOR/TAX in its efforts to achieve its vision is to not proceed with the procurement and implementation of an ITMS.

Risks fall generally fall into three categories: (1) technology, (2) business, and (3) delivery risks.

1. Technology Risks

Technology risks are technical or performance limitations that endanger the project's success.

Technology risks with a high level of importance and impact include:

- Recreating the "legacy trap" – committing to a solution not capable of meeting future needs; this risk speaks to concerns about obsolescence, flexibility, and expandability
- Opting for "cutting edge" but unproven technology
- Imposing technical requirements that needlessly limit the range of viable solutions that may be considered; for example, imposing Alaska-specific requirements that preclude consideration of solutions that have been successful elsewhere
- Inadequate assessment of solution capabilities, architecture compatibility, and system functionality
- Inadequate planning for future maintenance and support

2. Business Risks

Business risks are those impediments that prevent the organization from realizing the business benefits of the new technology. Business risks with a high level of importance and impact include:

- Inadequate resources are made available for the project
- A reluctance to change Alaska-specific business processes to take advantage of modern integrated tax solutions
- An insufficient emphasis is placed on training, thus staff is not able to effectively utilize the new technology

3. Delivery Risks

Delivery risks are those that affect project implementation. Delivery risks with a high level of importance and impact include:

- Using an unproven or out-dated implementation methodology
- Lack of top management commitment and involvement
- Ineffective or weak project management without clear oversight and decision-making authority
- Not dedicating the right people to the project including a sufficient number of business and technical resources
- A wavering focus on scope, deadlines, and budget
- Inadequate internal and external communications
- Insufficient staff involvement and buy-in; in Alaska, this risk has a geographic dimension due to the separation of staff in Anchorage and Juneau

An effective mitigation strategy needs to focus on three key elements: choosing a sound implementation approach (See *Alternative Approaches*); using an effective procurement process that results in the selection of a strong solution and trusted business partner (See *Preparing for Procurement*); and carefully planning and managing the project to ensure successful delivery (See *Project Management Plan*).

D. Alternative Approaches

The modernization of an agency's tax administration is a complex and risky undertaking. The strategy an agency chooses as it goes through the modernization process has a significant impact on its chances of success and the cost and schedule of the project, as well as an array of ancillary issues such as system functionality and performance, user training, maintenance, and future system enhancement.

Options available to states desiring to implement a modern, ITMS include custom, transfer, and commercial off-the-shelf (COTS) systems. These approaches are defined as follows:

- **Custom Built System:** Building an application system specifically for a single customer. Normally, a custom system is designed and built from the ground up for a specific agency by in-house resources, vendor resources, or some combination of the two.
- **Transfer System:** Obtaining a system used in another jurisdiction and fitting it to meet another customer's needs. A transfer system in this context is software in use at one revenue agency that is transferred, installed, and adapted to meet the needs of another revenue agency.
- **COTS System:** Obtaining a ready-made package designed to be configured to meet the needs of many customers. COTS in this context is a software product developed by a third-party who controls its ongoing support and evolution. It is bought, licensed, or acquired for the purposes of integration into a revenue agency. A COTS product might not allow modification at the source code level, but normally includes customization mechanisms to allow for easy extension and tailoring to meet each agency's requirements.

1. Industry Trends in the State Revenue Market

There has been considerable evolution in the state revenue market for tax systems in the past three decades. In the 1970s and 1980s, custom systems were the only option. Systems were built in-house or by vendors, and they often addressed a specific functional area such as registration, returns processing, collections, or audit. Many of the legacy systems states are seeking to replace today are siloed, custom systems with limited functionality built on aging platforms.

It is important to identify critical risk factors so that a strategic approach, effective procurement process, and a well thought out implementation plan are in place to maximize the opportunities for success.

The concept of an ITMS built on a single platform capable of supporting multiple tax programs and functions had significant technical and business advantages and revenue agencies started moving in that direction. Systems were self-built or built by IT service providers such as IBM, Andersen Consulting, and Unisys.

In the late 1980s, the “transfer system” concept became an option for state tax agencies. Transfer systems offered advantages of reduced cost and risk because the core system already existed and was in production operation elsewhere. The existing code of a transfer system provided a head start on development. The additional development activities focused on changing existing code and adding new code to meet different business and functional needs of another jurisdiction. Once a transfer system was completed, it retained many characteristics of a custom system – a system built to meet the requirements and needs of a specific jurisdiction. Like a custom system, the jurisdiction owned the code and was responsible for modifying and changing it, possibly with vendor assistance, as changes in legislation or business requirements dictated.

Transfer systems were a popular option from the mid-80s through to the early 2000s. At least two vendors marketed and implemented transfer solutions – CGI/AMS (Advantage Revenue) and Accenture, (TAS).

COTS became an option for state revenue agencies after the turn of the 21st century. A Gartner Industry Research report, *COTS Is Becoming a Viable Option for Tax and Revenue Agencies’ Application Modernization*, (Gartner, 2008) notes,

“Historically, tax and revenue agencies preferred to custom-build mainframe-based systems, because the early stages of the maturity of applications and application development approaches made it difficult to cost-effectively build commercial off-the-shelf products with sufficient architectural flexibility to adjust to the variety of regulatory and business needs” (p. 2).

COTS solutions offer advantages such as lower risk, reduced cost, and quicker deployment of proven “out-of-the-box” functionality. Rather than building from the ground up or rewriting or replacing another agency’s code, development focuses on tailoring extensions through configuration to meet a jurisdiction’s unique business requirements. With many business rules (such as tax rates, penalty and interest rules) being configurable, changes can be made quickly without the need to rewrite code. Similarly, new tax types can be configured in the solution just as existing taxes are configured during the implementation project.

The ownership model of a COTS solution differs from custom and transfer alternatives since the product code is proprietary – the jurisdiction has a license to use it but does not own it. The responsibility for keeping up with changes in technology and core functionality is delegated or outsourced to the COTS vendor. This can be seen as an advantage since adapting to evolving technology is a significant

undertaking and the ability to regularly refresh technology is appealing. However, some agencies view lack of source code ownership as translating to lack of control.

A COTS solution also offers agencies an upgrade path as new software versions and technology become available. Although upgrading to new versions still requires some work, it is less resource-intensive than a technology model that required the periodic replacement of legacy systems.

The different ownership models for custom and transfer solutions in comparison to COTS mean different life-cycle cost structures. A COTS system typically has lower implementation costs than custom or transfer solutions, and jurisdictions need to plan for on-going software maintenance costs to keep current with service packs and new versions of the software. Upgrading to a new software version may or may not require the assistance of the vendor depending on the capabilities of the in-house IT unit and the significance of the changes from version to version. Implementation costs for a custom or transfer system are typically higher than a COTS solution, and jurisdictions need to plan for periodically rewriting, re-platforming, or replacing the legacy system.

Since 2000, COTS solutions have become the predominant option for an ITMS in state revenue agencies within the United States. In thirteen contract awards between 2000 and 2005, nine were for COTS solutions, three were for transfer solutions, and only one was a custom build. In fourteen awards between 2006 and 2010, twelve were for COTS solutions and two followed a custom approach. One of the two was a project to rewrite legacy system COBOL code to Java (Maine). The other was a custom-build project which produced the prototype for a COTS product offering (South Carolina). There have been no transfer system implementations in the past five years.

Since 2000, COTS solutions have become the predominant option for an ITMS in state revenue agencies within the United States.

Table 1 lists the approaches states have taken in implementing an ITMS during the past ten years.

The dramatic shift towards COTS solutions in the state revenue market may be based on experiences some agencies have had with other approaches.

- In the early 1990s, the New Mexico Tax and Revenue Department initiated a project to modernize its computer systems by designing and building its own custom system that would integrate its tax types into a single business application. Nine years and \$49 million later, only one tax program was in production and a second under development. In early 2001, New Mexico decided to halt further development and acquire an off-the-shelf package through a competitive procurement process.
- Mississippi started a custom project in the late 1990's, but the tax system never was completed. Attempts to go live with the first of the 38 taxes in 1997 and 1998 failed and a third version of the

tax system provided in January 1999 had so many defects that testing could not be completed. Mississippi currently has a procurement process in progress and is seeking a COTS solution.

- Montana abandoned a custom system project after spending \$39 million. In 2003, the Montana Legislature directed the agency to shut down the project due to data integrity and stabilization issues, and an overall lack of confidence in the system. The department was instructed to find a replacement system with a proven track record in another state. The resulting RFP specified a COTS solution.

Table 1: State Approaches to ITMS (2000-2010)

Custom	Transfer	COTS
Maine	Arizona	Alabama
New York	Connecticut	Arkansas
South Carolina	Nevada	Colorado
		Florida
		Georgia
		Idaho
		Illinois
		Kentucky
		Louisiana
		Maryland
		Michigan
		Minnesota
		Montana
		New Mexico
		North Carolina
		North Dakota
		Ohio
		Utah
		Vermont
		West Virginia
		Wisconsin

There are currently state revenue agency procurement processes in progress in Massachusetts, Pennsylvania, Mississippi, Oklahoma, and California (Franchise Tax Board). The Pennsylvania, Mississippi, and Oklahoma RFPs specifically request responses for COTS solutions. The Massachusetts and California RFPs do not specify or restrict the type of solution so long as responses meet the state's requirements.

Today, there are at least five companies with COTS solution offerings for the US market:

- SAP (Tax and Revenue Management)
- Revenue Solutions, Inc. (RSI Premier)
- Fast Enterprises (GenTax)
- Oracle (Enterprise Taxation Management or ETM)
- Tata Consultancy Services (Tax Mantra)

To our knowledge, there are no vendors actively marketing transfer system solutions for integrated tax in the US market today. In the past there were two vendors who marketed and implemented transfer solutions – CGI/AMS (Advantage Revenue) and Accenture (TAS). Neither of these companies have marketed or bid these solutions in the past five years. CGI is currently implementing Oracle's ETM product in several states and Accenture is implementing the SAP revenue solution in one state and has bid the SAP solution in several other states.

Custom systems remain an option for state revenue agencies. A custom solution can provide a high degree of flexibility which may be important for an agency that is very satisfied with its existing business processes and does not want to adapt them to a COTS solution. Custom systems, however, pose a higher degree of implementation risk and, historically, have been a more costly option.

There are undoubtedly a large number of IT service companies, some with revenue agency experience and many without, which may be interested in the opportunity to develop a custom tax solution. Companies active in the revenue market include Accenture, Capgemini, CGI, Deloitte, IBM, PricewaterhouseCoopers, and Unisys but their level of interest in building a custom solution and, more specifically, their interest in the Alaska market, are not known. Also, there is little information available about recent state revenue agency experiences with custom ITMS solutions, particularly for states considered comparable to Alaska. If there is an interest in pursuing a custom solution and learning more about the vendor community as well as custom system pricing, DOR/TAX should consider issuing a Request for Information (RFI) specifically inviting responses from vendors interested in proposing a custom solution.

2. DOR/TAX Experience

DOR/TAX has previous experiences with custom and transfer solutions, both which did not produce the desired results.

a) Custom Systems

Three of the agency's existing systems, TAS, CPS, and DEE Excise, are custom built systems. DOR/TAX indicates that they provide insufficient functionality, and are complicated, expensive, and time consuming to modify and maintain. Not all data needed to track and report on tax types is collected causing information provided to be incomplete. In planning for an ITMS, DOR/TAX intends to replace all three systems.

b) Transfer Systems

One system DOR/TAX uses for two tax types was a transfer system called Data Entry and Examination Motor Fuel/Corp. The current version neither meets the needs of the Tax Division nor can it be enhanced.

In evaluating the transfer approach, the *TRIMS* (ADOR/TAX, 2009) report noted:

"This option was attempted back in 2000 with the purchase of the state of Wyoming's Mineral Tax System, a third-party product from Computing Alternative, Inc. This project, involving the adaptation of the product for Alaska's Corporate Income Tax and Motor Fuel Tax types, was unsuccessful due to cost overruns, system instability, data integrity issues, and the inability to generate meaningful reports. All of these problems have contributed to an existing system that requires significant business process work arounds and that operates at a 'snail's pace.' In some instances, it is actually faster to manually process a return than utilize the system. In addition, this system 'crashed' a few years ago making it impossible to supply required reports to the Federal Highway Administration (FHWA) regarding motor fuel used on Alaska's highways. Our failure to report almost resulted in FHWA withholding federal highway funds from Alaska's Department of Transportation" (pp. 14-15).

3. DOR/TAX Research

In 2007 and 2008, a series of three reports were prepared for DOR/TAX by the Alaska Information Technology Group (AITG). The studies identified requirements for an Oil and Gas Tax revenue system, conducted a high-level assessment of two approaches to developing a new system (custom and COTS), and reviewed two COTS solutions.

In the *Oil and Gas Tax System: Solutions Analysis*, AITG (2007) identified business, functional, and system requirements and, based on the preliminary requirements gathering phase of the project concluded,

“the DOR needs to develop or acquire a comprehensive flexible, computerized system to track, calculate, and report tax data, starting with the data associated with the oil and gas production tax” (p. 2).

In the second study, *Oil and Gas Tax System Solutions Analysis*, AITG (2007) further investigated two potential solutions, a custom and a COTS solution. They concluded both the custom and the COTS solution can meet the requirements, and

“...careful evaluation of all available options should be considered before moving forward with a solution” (AITG, 2007, p. 23).

The third AITG study, *Oil and Gas Tax System: COTS Solutions Analysis* (AITG, 2008), further analyzed two COTS solutions. As a part of the study, five states were surveyed that had implemented custom and COTS solutions for Oil and Gas Taxes. The three custom solutions all took longer to complete than had been scheduled (timeframes were underestimated by 33% to 50%) while the two COTS projects were completed on time. On a scale of 1 to 10 with 10 representing high satisfaction, the custom systems received ratings from New Mexico, North Dakota, and Wyoming of 7, 8, and 5 respectively. The COTS systems received rating from Louisiana and Montana of 10. Louisiana and Montana indicated they would “select the same system if they were to implement a new system today” (AITG, 2008, p. 10). Two of the three states who chose custom solutions (New Mexico and Wyoming) were not satisfied with the outcome. New Mexico said they “would not build the same system today” (AITG, 2008, p.10). Wyoming indicated the system was not properly developed, and work-around solutions became standard business practices. The system was described as “just works” (AITG, 2008, p. 10). The study recommended that Alaska budget \$20 million for the cost of implementing a COTS solution for Oil and Gas Taxes (AITG, 2008, p. 10).

ADOR/TAX (2009) produced *TRIMS* which evaluates five alternative strategies:

- “Maintain and upgrade the existing system and method of operation
- Transfer an existing system from another state
- Transfer and modify an existing system from another state
- Custom build a new system
- Acquire and implement a COTS product” (p. 10)

DOR/TAX evaluated each option in terms of cost, ability to satisfy requirements, business process impact, time, and risk.

The *TRIMS* (ADOR/TAX, 2009) report concluded acquiring and implementing a COTS product is the best recommendation for the *TRIMS* project. COTS systems are developed by businesses that specialize in state and local tax revenue systems. In terms of time, the COTS solution is capable of a faster

implementation because the initial phases of production are not spent building core framework. Risk is minimized when using a COTS solution and is primarily contingent upon selecting a vendor who is successful in managing solutions and who can provide technology updates. ADOR/TAX (2009, p. 21) states,

“COTS solutions typically have been tested in the user community at large and are considered a proven solution. At its core, the software will provide a stable and proven framework, which requires some configuration to meet the business requirements.”

“A custom solution, on the other hand, has not yet been proven and the framework must be developed from scratch. Typical risks include poor performance or unworkable code, where some features do not work as intended. These risks are compounded by the number and complexity of the business requirements, the programming languages and platforms utilized, and the systems that need to be integrated.”

“Agencies are sometimes wary of the COTS approach because they fear that future changes to the product will not be under their control, or that a vendor may eventually abandon support for the product or go out of business altogether. This risk can be significantly mitigated by selecting a vendor with a proven, long-term track record in designing, delivering, and supporting a revenue management solution, not as a sideline but as the primary strategic focus of their product offering; and who has demonstrated a commitment to maintain currency with evolving industry-standard technology platforms.”

“All states participating in the Tax Division’s 2008 survey indicated satisfaction with the performance and scalability of their COTS tax management system implementations.”

Furthermore, ADOR/TAX (2009, p. 19) concluded,

“Considering all evaluation criteria together – cost, satisfaction of requirements, business process impact, time, and risk – the COTS implementation strategy represents the highest probability for a successful TRIMS project outcome.”

“After careful internal research and analysis, the Tax Division recommends that it is in the best interest of the State for the Division to acquire a commercial off-the-shelf (COTS) system that can be configured to meet the needs of the Division, the State, and the taxpayers and stakeholders we serve.”

4. Next Steps

- If DOR/TAX is interested in a custom solution, it should consider issuing a Request for Information (RFI) specifically inviting responses from vendors interested in proposing a custom solution for DOR/TAX. The RFI should request a company profile, information about the technology to be used, a system description, pricing and schedule information, the company's experience implementing similar systems in jurisdictions comparable to Alaska, and any other information DOR/TAX believes would be useful in evaluating the costs and benefits of further pursuing a custom solution
- If DOR/TAX is interested in a COTS solution, they should issue an RFP specifying that responses must propose a COTS solution. In recent years, this approach was used in Arkansas, Mississippi, and Oklahoma.
- If DOR/TAX is interested in either a COTS or transfer solution, it should issue an RFP specifying that responses must propose a COTS or transfer solution. In recent years, this approach was used in Utah.

VI. Costs and Benefits

This section provides high-level information about the cost components of an ITMS and presents a range of costs for DOR/TAX as it estimates and budgets an appropriate level of resources for a new system. FAST reviewed and analyzed information DOR/TAX previously gathered from other state tax agencies about costs and benefits of an ITMS and supplemented it with additional survey information. Potential benefits and various funding approaches are presented in this section.

For an ITMS project, one of the critical risk factors is inadequate funding. If project costs are underestimated, the desired scope of the project may not be delivered, or the project may go over budget. It is important to set a realistic level of funding, recognizing that major components of the project will be subject to bid with multiple vendors providing pricing proposals for goods and services.

A. Cost Components

Cost components for a tax system project generally fall into five categories:

- Software
- Implementation services
- On-going maintenance and support
- Hardware
- Project operating expenses

Vendor-related cost components include software and implementation services. For budgeting purposes, these two cost components may be bundled together. Once the project is complete, there will also be on-going software maintenance and support costs.

In addition, a project incurs hardware costs and internal project operating costs such as those related to project space, equipment, and travel. If agency staff members (business and technical) are “loaned” to the project, they do not usually represent additional, marginal costs for which a budget is requested. However, this is an aspect of a project that needs to be carefully managed since a significant number of agency staff will be committed to the project – many on a full-time basis. If additional project-related staff are requested, those costs should be included in the project’s operating budget request.

1. Software

The major element of software costs is the integrated tax software itself. There will also be third-party software licensing expenses for operating systems and database support.

Vendors use different pricing models for software licensing. Variations include enterprise licenses with no functional or program-based restrictions, and restricted licenses that limit permitted uses to only tax types or functionality that is specifically in-scope. Some vendors price licensing based on the number of users or “seats” while others are not limited with respect to the number of users, desktops, servers, or

office locations. As vendors respond to the RFP, it is important to understand the basis for their software license pricing, and to have them specify license restrictions and limitations.

2. Implementation Services

Vendor services are usually the single largest cost component for an ITMS implementation project. DOR/TAX is planning a project to replace all 22 taxes, implement more aggressive e-filing, implement a complete Data Warehouse, and integrate imaging. Required services will include services for system configuration, development, testing, conversion, and training. Consulting services to meet a variety of other needs may be requested or proposed including those related to business process redesign and project management. Project management includes the vendor's project manager and, at the discretion of the agency, may also include an independent project manager who works on behalf of the agency.

3. On-going Maintenance and Support

Software maintenance costs provide for modification of the software after delivery to cover bug fixes, improve performance, or add functionality. Sometimes software maintenance takes the form of a "warranty period" beyond the implementation project. Software maintenance may or may not include access to future version enhancements. In the initial project budget, it may be desirable to provide for some level of maintenance beyond the implementation project. For example, if the project is expected to be implemented over a three-year timeframe, including all costs for a five-year period may be prudent so that on-going software maintenance are visible and can be factored in to reflect both project-related and post-project costs. On-going support services may include vendor resources necessary to supplement agency resources after the implementation project is complete.

4. Hardware

Major hardware costs include servers running the ITMS application, related databases, storage area network (SAN) capacity, developer workstations, and client workstations. This hardware supports the production, development, and testing environments. Hardware needs are usually site-specific since they depend on whether an agency's existing hardware meets the new solution's specifications. In addition, there may be network, cabling needs, etc. that would be unique to each site.

5. Project Operating Expenses

Project operating expenses consist of general overhead expenses necessary to support a project including project space, equipment, travel, and other internal costs necessary to support activities, such as training and testing. These expenses are typically site-specific and reflect the marginal costs over and above an agency's normal operating expenses. They will vary depending, for example, on whether there is existing agency space to accommodate a project office. For DOR/TAX, travel costs should include project related travel that will be necessary between Juneau and Anchorage.

B. Pricing Strategy for DOR/TAX

In setting a budget for a major IT project, a jurisdiction wants to be sure it is able to obtain the functionality, performance, and delivery it seeks at a fair price. For an ITMS project, one of the critical risk factors is inadequate funding. Setting a budget too low may result in getting a system that does not meet the agency's needs. A jurisdiction also runs the risk of limiting the number of vendors that respond to an RFP and receiving attractively priced responses that carry high business and delivery risks.

Two primary ways used by jurisdictions to get information helpful in setting a budget:

- Information from the vendor community
- Information from other states in the process of implementing or have implemented an ITMS

DOR/TAX has used both of these means. For the past three or more years, the agency has participated in events such as the Federation of Tax Administrators Technology Conference and Exhibition, met and consulted with vendors to understand their product offerings and pricing, seen demonstrations of multiple solutions, and has had an independent consulting firm analyze different software solutions. They have received confidential cost estimates from three COTS vendors. DOR/TAX has also formally and informally surveyed other states to get information about project costs and schedule, as well as user satisfaction.

A budget for an ITMS for a five year period is estimated to be **\$30 to \$35 million**, and DOR/TAX is requesting a budget of **\$35 million**.² This budget should be sufficient to attract a number of vendors offering a range of solutions to respond to an RFP. The strategy is prudent in that it allows the forces of competition to work in Alaska's favor by encouraging competition and by inviting competitive RFP responses to ensure the state is able to select the best system at a fair price.

C. Integrated Tax Management System Budget

Budget information for an ITMS project is presented by cost component for a five-year period. In developing these estimates, it is assumed that an RFP would solicit responses from vendors for software, services, and maintenance and support for a five year period. Since the implementation project itself may take less than five years, the vendor would be required to include maintenance and support in its pricing from the end of the implementation project through the fifth year. For example, if a vendor proposed a 2½ year implementation project, they would include 2½ years of maintenance and support in their response. If a vendor proposed a four year implementation project, they would include one year of maintenance and support in their response.

This provides flexibility to the vendor to propose costs and a schedule that they believe to be realistic and feasible, while providing to DOR/TAX assurances the project will be completed within five years and that all maintenance and support costs are included for a five year period.

² Due to proprietary vendor information, FAST estimated the budget based on information from other states.

Faster implementations will include longer periods of maintenance and support while longer implementation projects will include a shorter period of maintenance and support. DOR/TAX may wish to specify the maximum amount of time it will consider for the duration of the implementation project itself, e.g. four years.

Also, it is important to realize this approach will invite differences in how different vendors allocate pricing between implementation services and maintenance and support.

1. Vendor Software and Services

A budget for vendor software and services in the range of **\$23 to \$27 million** is within industry norm. This amount takes into consideration the number of tax types to be implemented (22), the functionality in scope including a data warehouse, taxpayer on-line services, imaging integration, and the services of an independent project manager. In substantiating this estimate, primary reliance is placed on recent cost information (2007 – 2009) obtained from other states that have procured and are in the process of implementing an ITMS. Secondary reliance is placed on cost information from small states (population less than 3 million) that implemented an ITMS in prior years (2003 – 2006).

It is important to note this estimate does not take into consideration confidential price information DOR/TAX has obtained from multiple COTS vendors. DOR/TAX should validate the estimate by comparing it to the information they have obtained.

This estimate may not be reflective of costs for a custom solution. If DOR/TAX would like more information about vendors and potential costs of a custom solution, they should consider issuing a Request for Information (RFI) specifically asking for information from the vendor community about offerings and pricing.

2. Maintenance and Support

A budget of **\$2.0 to \$2.5 million** per year for on-going maintenance and support after the project is completed is within the industry norm. For purposes of total project estimates shown, it is assumed the implementation project will be completed within three years, so two years of maintenance and support costs are included. Note that a faster implementation may require a higher amount for maintenance and support (more years), while a longer implementation may require a lesser amount (fewer years).

3. Hardware

DOR/TAX has estimated hardware related costs to be **\$1.375 million** including costs for acquisition, installation, and testing.

FAST independently reviewed DOR/TAX's hardware estimates and based on experience in other jurisdictions determined this estimate to be reasonable. During the RFP process, DOR/TAX should request vendors to specify hardware requirements specific to the proposed solution so that hardware costs can be more precisely determined for each solution.

4. Project Operating Expenses

DOR/TAX has estimated internal operating costs to be **\$1.0 million**, including funds for project office space, travel, and training. In addition, **\$325,000** is associated with system integrated testing.

5. Total Project Budget

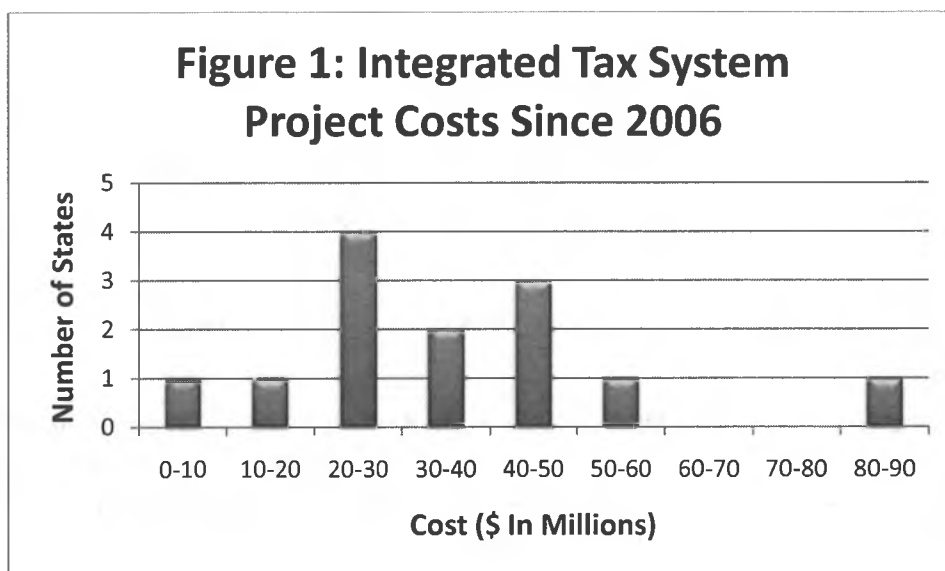
Table 2: Estimated Project Costs

Component	Amount – Low (millions)	Amount – High (millions)
Vendor Software and Services	\$23.0	\$27.0
Hardware	\$1.375	\$1.375
Project Operating Expenses	\$1.325	\$1.325
Maintenance and Support (2 years)	\$4.0	\$5.0
Total	\$29.7	\$34.7

D. Comparison Information from Other States

Since the year 2000, most state tax and revenue agencies (27 out of 50) have implemented or are in the process of implementing an ITMS. This provides a breadth of experience for DOR/TAX to draw from. The 27 states differ considerably in their population, total state revenues collected, tax structure, taxpayer base, and the complexity of individual tax types. There is also considerable variation in the scope of the tax system projects the states have undertaken.

Within the past five years, there have been 14 ITMS contract awards. Information obtained for 13 of the projects indicates system costs have ranged from **\$8 million** to **\$87 million**, with the six projects initiated since 2008 averaging **\$43 million**. Figure 1 displays the range of costs for these 13 projects.



While this provides a “ballpark” indicator of total costs, individual state procurements are not perfectly comparable – the goods and services states choose to purchase often vary. Procurements typically involve software license and implementation services, while some may also include hardware, data warehouse and associated analytics, imaging, extended maintenance agreements, and/or extensive consulting services to address a variety of needs. Moreover, the scope of the implementations may range from a small number of taxes (1 to 4) to all of the tax types administered by the revenue agency (possibly 50 or more). For example, the two projects with costs under \$20 million shown in the graph above involved the implementation of one tax with limited functionality (Michigan) and four taxes (Vermont). Given differences in project scope and the different vendors that may be involved, the duration of these projects also varies.

While the number of taxpayers in a jurisdiction has some bearing on costs, the complexity of the taxes, desired functionality, and the number of tax programs are much more significant factors. A high volume of taxpayers can affect software and hardware scalability and performance, but the functionality needed to process and administer a tax is not materially affected by a large or small number of taxpayers.

Generally, more recent procurements provide stronger indicators of current costs since they better reflect the current market. However, completed projects may provide better evidence of the benefits derived from an ITMS project since those jurisdictions have had the opportunity to establish a track record benchmarked against the performance of their legacy systems.

1. Comparison States – Small Populations

For purposes of providing additional comparative information related to small states, procurements in states with populations of less than three million during the last five years are examined in closer detail. This includes three states: Utah, Vermont, and Arkansas. To broaden the pool, procurements initiated since 2005 in states with a population of less than three million were also included, bringing in North Dakota and West Virginia. In addition, Montana is included in the comparison since Alaska often compares itself with Montana, both because of similar populations (less than one million) and because Montana, like Alaska, has a high dependence on severance taxes. Montana’s project initiated in 2003, eight years before the potential start of an Alaska ITMS project.

Note: Information provided from other states is for the initial implementation project only. In some cases, additional tax types or functionality has been subsequently added. These additions are not included in the comparison since subsequent, incremental costs are harder to identify and track making comparisons are less reliable. Table 3 displays comparative summary information.

Table 3: Comparative Summary Information

Inception Date	State	2010 Population (000)	2008 Total State Tax Revenue* (Millions)	In-Scope Tax Types	Project Duration	Project Status
2003	Montana	975	\$2,457.0	53	48 mo.	Completed
2005	North Dakota	645	\$2,312.1	19	24 mo.	Completed
2005	West Virginia	1,819	\$4,881.9	42	42 mo.	Completed
2006	Utah	2,786	\$6,109.3	26	37 mo.	Completed
2007	Vermont	622	\$2,544.2	4	32 mo.	Completed
2008	Arkansas	2,889	\$7,530.5	46	48 mo.	In-Progress
2011	Alaska	698	\$8,424.7	22	--	Proposed

*Source: 2008 Annual Survey of State Government Finances, U.S. Bureau of Census

Mississippi (population 2.952 million) is currently engaged in an ITMS procurement process. DOR/TAX should monitor the progress and results of this procurement since it is the first one involving a state with a population of less than 3 million since 2008. While a contract is yet to be awarded, it is worth noting that Mississippi received five vendor responses to their RFP.

Below is a short description of each of the six state projects.

a) Montana

In the late 1990's the Montana Department of Revenue chose a "design and build" (custom) strategy to modernize its many non-integrated and inflexible legacy systems. In 2003, after spending \$39 million, the Montana Legislature directed the agency to shut down the project due to data integrity and stabilization issues, and an overall lack of confidence in the system. The department was instructed to find a replacement system with a proven record of accomplishment in another state.

Montana acquired a COTS solution and utilized a "proof of concept" approach, initially implementing six taxes over an 11-month period. Following the successful and on-time rollout of the first phase, subsequent phases brought 53 different tax types into production over the project's lifespan of 48 months.

b) North Dakota

The North Dakota project was a two-year, multi-phased project to convert most of the tax department's many aging computerized tax processing systems to a modern ITMS capable of quickly adapting to the state's frequently changing tax laws and regulations. The project replaced legacy tax systems designed 40+ years ago. Because legacy systems were limited by their age and effectiveness, the agency resorted to using supplemental tools such as MS Access and MS Excel to process and maintain significant elements of tax administration data.

North Dakota considered three alternatives for its modernization project:

- Migrating the existing systems to a modern hardware platform
- Designing and building a new system from scratch (custom development)
- Implementing a COTS solution

North Dakota elected a COTS approach in order to reduce risk, reduce cost, shorten the implementation schedule, take advantage of upgrades made to the core product, and enable the state to adapt quickly to future tax changes and business challenges. The project started in July 2005 and was completed in June 2007, bringing 19 taxes types into production during the four phases of the project.

c) West Virginia

As recently as 2006, the West Virginia State Tax Department used 23 out-dated operating systems to administer 42 different taxes. Separate systems created a segmented work environment for the department and led to inaccurate data and erroneous billings. They also inhibited good taxpayer service – tax service employees had to go into as many as nine different systems to answer a taxpayer's question. IT staff struggled with inflexible software tools and the department was able to make only limited changes to reflect new laws enacted by the legislature.

West Virginia started its ITMS project in 2005, implementing a COTS solution with the goals of enhancing tax collections, bringing the state tax administration into the 21st century, and providing taxpayers with the best possible service. Forty-two taxes rolled out over a 42-month project consisting of five phases. The state has been able to retire 20 of its legacy systems.

d) Utah

The Utah State Tax Commission administers over 40 major taxes and fees. Several of its largest taxes were administered using systems developed more than 20 years ago that were structured in silos containing one or more related tax types. The systems had grown increasingly complex, inflexible, and difficult to maintain. Facing the possible need to implement legislatively directed changes to the tax code, the Tax Commission feared it would be difficult, if not impossible, to implement changes using existing systems and technologies.

The Tax Commission's goal was to replace its core tax systems, and its RFP invited proposals for either COTS or transfer solutions. They selected a COTS solution and started the implementation project in April 2006. Imaging integration and several additional tax types were later added to the scope of the project including International Fuel Tax Agreement (IFTA) and International Registration Plan (IRP). As of September 2010, a total of 29 tax types have been implemented into production.

e) Vermont

Vermont undertook its ITMS project in 2007 based on the need to replace aging mainframe software applications with more modern and functionally rich software. Retirements of key mainframe developers reduced the department's ability to continue to maintain its older mainframe-based tax

systems which had evolved over a 30 year period. The agency also relied on PowerBuilder applications, built in the late 1990s, modified with customizations to provide functionality in support of business needs and statutory changes.

Vermont's strategy was to undertake a limited project (4 taxes), and expand it sometime in the future for full enterprise-wide use. This approach would allow the agency to consolidate processing on the new application by migrating remaining processing from legacy systems. Vermont selected COTS technology to leverage vendor support, better utilize internal IT capabilities, avoid technological obsolescence via upgrades, and reduce overall risk.

f) Arkansas

The Arkansas Division of Revenue's legacy tax systems consisted of four major tax systems plus a tax collection system designed and implemented between 1985 and 1993. Designed to support the reporting and collection of taxes, the systems did not have sufficient features to manage current tax laws. Reports requested from the legislature and executive branch agencies were very time consuming and difficult to produce. Given the age and architecture of the systems, they were difficult to manage and maintain, inflexible, and incapable of providing adequate support for tax section needs.

Arkansas issued an RFP seeking a COTS solution to replace their legacy systems. They started their 4-year project to implement 46 taxes in 2008. They have completed two of five scheduled phases and currently have 21 tax types in production. The project is scheduled to be completed by the first quarter of 2012.

2. Comparison of Scope and Component Costs

Table 3 compares the initial scope of ITMS projects in the six comparison states with the proposed scope for Alaska. In some cases, additional tax types and functionality were added into scope after the project was initiated.

Table 4: Comparison of Initial Scope

State	Data Warehouse	Taxpayer On-Line Services	Imaging	Other
Montana	Yes	No	No	--
North Dakota	Yes	No	No	Remote Support for Field Audits
West Virginia	Yes	Yes	Yes*	--
Utah	Yes	Yes	No	--
Vermont	No	No	No	
Arkansas	Yes	Yes	No	Remote Support for Field Audits and Collections
Alaska	Yes	Yes	Yes	--
*Integration with a preexisting imaging solution; excludes imaging system hardware and software				

3. Vendor Software and Services

For purposes of this comparison, vendor software (including third-party software) and services are combined since a breakout between these two items was not obtained.

Table 4 compares vendor software and service costs for the ITMS projects in the six comparison states. They range from **\$7.8 million** to **\$27.0 million**. The number of tax/account types in scope range from 4 to 53, and the durations of the project ranged from 24 to 48 months. The functional scope also varies; five of the six include data warehouse functionality, three out of six include taxpayer on-line services, and only one out of the six includes imaging integration. Reasons for including or excluding certain functionality in a project's scope vary. For example, some agencies already have on-line taxpayer services functionality that they do not wish to replace. In other instances, cost constraints cause an agency to limit its scope.

While vendor software and services costs gathered from the six small states provide some helpful information, its use is limited by several factors. First, the data is somewhat old. The information from Arkansas is more than three years old relative to the potential start date of an Alaska project, and the information from Montana is eight years old. Second, the costs only relate to two COTS vendors. Today, there are at least four companies with COTS solution offerings for the US market, including SAP, RSI, FAST, and Oracle. A fifth vendor, Tata, has also responded to state RFPs in recent years with a proposed solution.

<i>Table 5: Cost Comparison—Vendor Software and Services</i>				
State	Vendor Software and Services (millions)	Hardware (millions)	Inception Date	Tax / Account Types
Montana	\$24.8	n/a	2003	53
North Dakota	\$10.0	n/a	2005	19
West Virginia	\$20.8	\$1.5	2005	42
Utah	\$22.5	n/a	2006	26
Vermont	\$7.8	n/a	2007	4
Arkansas	\$27.0	n/a	2008	46

a) Maintenance and Support

Average maintenance and support costs obtained for the six comparison states ranged from **\$1.15 to \$2.55 million** per year.

b) Hardware

Among the six comparison states, only West Virginia's project costs were inclusive of hardware for a total of **\$1.5 million**. Many states are able to order hardware from pre-existing state contracts or may use separate procurements for hardware acquisition.

c) Project Operating Expenses

Project operating costs were not obtained from the comparison states since they tend to be based on factors and needs that are unique to each state.

E. Integrated Tax Management System Project Benefits

The benefits revenue agencies seek from a modern, ITMS generally fall into five categories:

- Increased compliance and the ability to collect revenues that are currently uncollected
- Operating efficiencies
- Enhanced taxpayer services
- More reliable data and improved reporting capabilities, both for external stakeholders and for internal management purposes
- Streamlining system maintenance through a unified technology platform

Below is a list of benefits DOR/TAX could expect to realize through an ITMS.

1. Increased Compliance

An ITMS is able to improve tax compliance by providing automated tools that enhance collection management, systematically identify and act on taxpayers who fail to file, improve audit selection, identify potential underreporting, and help discover taxpayers that not registered and paying taxes.

Currently, DOR/TAX does not have collection management tools that easily and quickly support the billing of underpayments and escalated actions to ensure payment. There is not a consolidated view of a taxpayer's accounts, so it is extremely cumbersome to determine if a taxpayer is current on all tax obligations, or may be due a refund for one tax yet have an outstanding balance for another. An ITMS would provide current and reliable accounts receivable information across all tax types, and enable DOR/TAX to support progressive actions to collect delinquent taxes, interest, and penalties.

Similarly, DOR/TAX does not currently have a means to identify systematically if a taxpayer has failed to file a tax return. Current, manual processes to detect non-filing are haphazard at best, and do not ensure timely identification and action. An ITMS would introduce the capability of determining if a taxpayer has failed to file an expected tax return and support rapid and automatic or employee-based actions to follow-up appropriately.

DOR/TAX auditors currently spend a high proportion of their time compiling, organizing, and reconciling data in preparation for an audit or examination. The manner in which the data is stored in numerous systems prevents easy retrieval of information. DOR/TAX must gather data from a variety of different

systems, databases, and spreadsheets, paper documents, and images of paper documents. Because it takes so long to prepare for an audit, fewer audits are completed and the audits that are performed take longer to complete.

Oftentimes, data cannot be retrieved and an agency employee will need to ask the taxpayer to provide it. This is time consuming and imposes a burden on the taxpayer. Current tools to analyze patterns of underreporting are limited to non-existent, and do not enable the agency to prioritize its audit resources effectively or focus its audit and examination activities on those areas of highest need. An ITMS would enable the agency to improve audit productivity and to target its audit coverage to maximize tax compliance.

DOR/TAX lacks tools to identify and pursue taxpayers that should be registered and paying taxes but are not. Modern data warehouse and discovery tools allow a tax agency to use internal and third-party data to discover potential non-filers and to follow-up appropriately through automatic or employee-based actions to ensure proper compliance and reporting.

2. Operating Efficiencies

DOR/TAX's current operating environment is characterized by a high degree of manual processes. Approximately 95% of the agency's business processes are manual, and many exist strictly to get information from one system or database into another or to reconcile information from multiple sources. DOR/TAX also uses manual processes for fundamental business purposes, for example, they distribute shared taxes of over **\$44 million** to 124 communities throughout Alaska in 2009. Multiple systems and data sources create the need for multiple and diverse processes, contributing to

An ITMS would provide current and reliable accounts receivable information across all tax types, and enable DOR/TAX to support progressive actions to collect delinquent taxes, interest, and penalties.

organizational silos and the need for specialized knowledge to carry out various agency activities.

A single, ITMS will present users with a consistent view of taxpayer information across all tax types and business functions. This facilitates a consistency of operations across the agency.

This streamlines training, since employees use a common system with the same look and feel. Once employees know how to use the system, it is easier for them to learn other duties and take on new tasks since they are using tools and workflows that are already familiar to them.

An ITMS enables automation of high volume, routine tasks allowing agency staff to focus on resolving exceptions and engage in other value-added tasks such as compliance and taxpayer services. An implementation project involving a COTS solution will not only focus on installing new software, but it

also involves redesigning business processes so they are consistent with the software's capabilities. The implementation project will provide the opportunity to streamline agency business processes and align them with the best practices incorporated into the solution.

A new ITMS will provide immediate access to current and historical information regarding work in progress, including operational and management reports and ad hoc requests for information. This will allow managers to plan work and track performance and to redeploy resources as necessary to address high priority needs.

The availability of timely and meaningful information will provide DOR/TAX with a solid basis to develop and utilize a set of performance metrics that are clear, meaningful, realistic, and measurable, and that drive behavior that is consistent its mission, vision, and goals. By DOR/TAX's own admission, current performance measures are not very meaningful or current since they are limited to information that is pieced together and extracted from multiple systems.

3. Enhanced Taxpayer Services

Current systems do not provide a complete view of a taxpayer's file across tax types and functions. Since information is stored in various systems, databases, and spreadsheets, it does not lend itself to a timely or complete snapshot of a taxpayer's activities and status. Since data cannot be readily shared, taxpayers may be asked to report the same information multiple times in different formats to support the needs of different sections and purposes. Difficulty of retrieving information also means that an agency employee may ask the taxpayer to resubmit tax return information, since, from the employee's perspective, it is easier to get the information from the taxpayer than relying on the agency's systems. Limited e-government capabilities also present a burden, especially to large taxpayers.

An ITMS provides real-time access to taxpayer information. Since information is available for all taxes for which a taxpayer is liable, it provides a current and complete view of a taxpayer's file including all tax types, all historical information, and all business activities for the taxpayer. This allows an employee to provide accurate information to a taxpayer about their account or to answer a taxpayer's question without having to look up information from multiple sources. It also supports a "one-stop" experience for taxpayers since they do not need to shop around the agency to find an employee who has access to the information they are looking for. A real-time system allows taxpayer information to be updated regardless of a user's location.

Customer service is enhanced by additional taxpayer self-services via the Internet. This not only supports on-line filing and payment, but enables taxpayers to update contact information, look at previously filed tax information, or file an amended tax return. It would allow DOR/TAX to provide reminders to taxpayers about upcoming deadlines and offer a secure communication channel supporting the exchange of confidential taxpayer information.

Currently, some taxpayers are required to report tax information using complex spreadsheets. Especially for taxpayers who report large amounts of data, this imposes a substantial burden. A modern tax system enables the filing of tax information via Electronic Data Interchange (EDI) which is a structured means to transmit data from a taxpayer's system to the tax agency's system. This not only offers taxpayers tremendous efficiencies, but it reduces potential errors that can occur when data is transcribed from the taxpayer system into a spreadsheet.

An ITMS is able to store, maintain, and retrieve a large amount of data. This capability will enable DOR/TAX to simplify reporting requirements so that taxpayers do not have to report the same information multiple times. It will also allow employees access to the information they need without imposing on taxpayers to resubmit information they have already provided to the agency.

Currently, a substantial amount of DOR/TAX's employees' time is spent compiling, organizing, and reconciling data and on manual business processes. This distracts the agency from being able to focus its attention on value-added activities such as taxpayer services and compliance. One symptom is the level of information, instructions, and regulations available to taxpayers. For a tax system reliant on voluntary compliance, taxpayer information and education is an essential component of effective tax administration. Automation of high volume and routine tasks, together with the elimination of activities currently devoted to compiling, organizing, and reconciling data from disparate systems, databases, and spreadsheets, will enable DOR/TAX to refocus its attention on improving taxpayer services and compliance.

The availability of timely and meaningful information will provide DOR/TAX with a solid basis to develop and utilize a set of performance metrics that are clear, meaningful, realistic, and measurable, and that drive behavior that is consistent its mission, vision, and goals.

4. Enhanced Reporting Capabilities

A major issue repeatedly encountered while preparing this report is the lack of information about workload and day-to-day operating statistics indicating how much work DOR/TAX is accomplishing using current systems. The totals for current receivables, refunds outstanding, refund interest paid to date,

and total taxpayer balance could be obtained by DOR/TAX but only if someone is pulled away from their assigned duties to gather information from spreadsheets, paper documents, or information from images.

DOR/TAX cannot easily produce reports required by the legislature and policy makers because current systems prevent timely, complete, and correct extraction of data. Information is fragmented in 17 systems used to administer different aspects of its tax types, along with over 100 MS Excel spreadsheets, used in unofficial side-systems to track information other systems do not capture.

In order to provide accuracy in reporting, excessive hours are spent comparing, fixing, and formatting data manually prior to producing information for reports. Even with this exceptional effort, reports are often misleading or inaccurate due to incorrect, incomplete data, and, despite the best attempts of the professionals in TAX, human error. Current systems offer very limited reporting capabilities, but tools available are inflexible and oftentimes prevent the agency from producing information in the form and format desired by the OMB, the legislature, or the Governor's office.

A modern ITMS provides an integrated solution with a consistency of information across all business activities. It ensures more reliable information and improved analytical capabilities with data collected, stored, and retrieved in a single database providing real-time access and query capability. It provides the ability to sort, group, and filter data, and to view it with customizable parameters, along with more advanced capabilities to visualize, analyze, drill-down, and manipulate information to meet a variety of reporting and analytical needs.

Modern systems not only support traditional, presentation-ready reports, but also provide online, ad hoc query capabilities. Systems exist for DOR/TAX to enable the agency to manage the day-to-day processes and to measure and monitor system performance, personnel achievements, and work load. DOR/TAX could benefit by moving personnel back to jobs defined in their personnel descriptions and away from data entry or manual number crunching. Systems are available to DOR/TAX that can capture data automatically and allow managers to work on exceptions, allow auditors to perform audits, and allow compliance agents to perform compliance activities. Reporting capabilities in an ITMS can support an enhanced and flexible view of a subset of the system's database and allow for faster, more accurate and more dependable forecasts, analysis, and response to stakeholders.

An ITMS further allows the collection of information and distribution through scheduled email to allow managers to stay connected at all times with the processes for which they are responsible. Alerts, executive dashboards, and user-created system queries place additional tools in the hands of managers, supervisors, auditors, and other personnel to allow more informed decisions and to enhance the management of a division's operations. FAST found many managers working without any of these common tools.

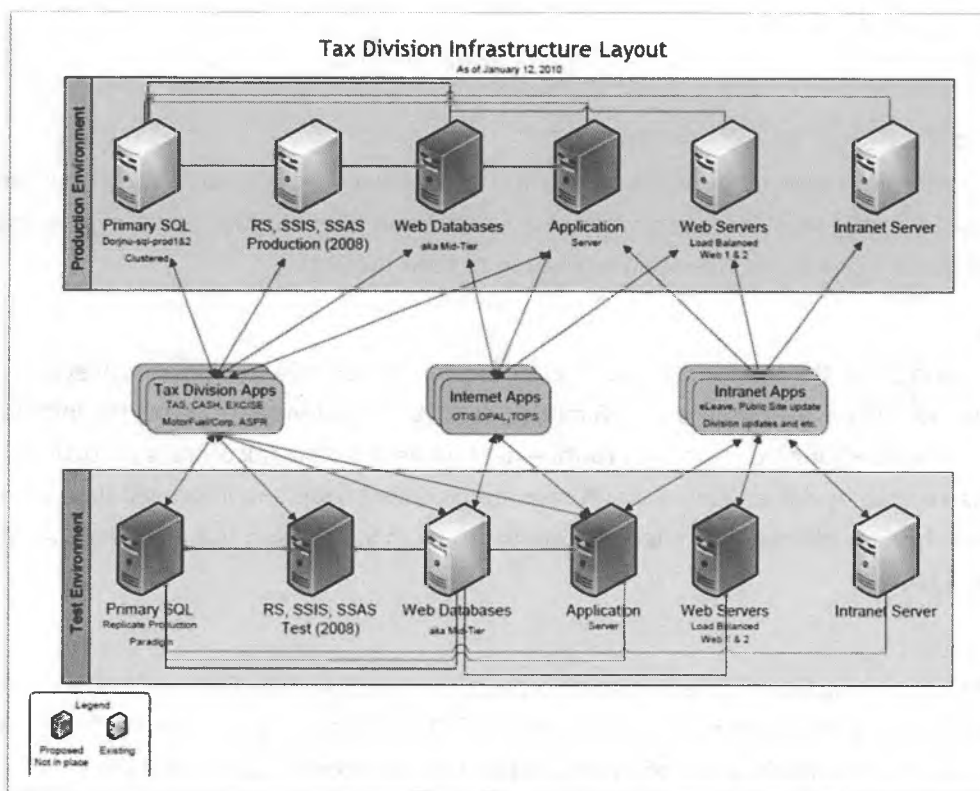
A data warehouse and OLAP cube capability extends information and analytic capabilities by enabling the loading, storage, and manipulation of DOR/TAX and third-party data. These tools leverage the

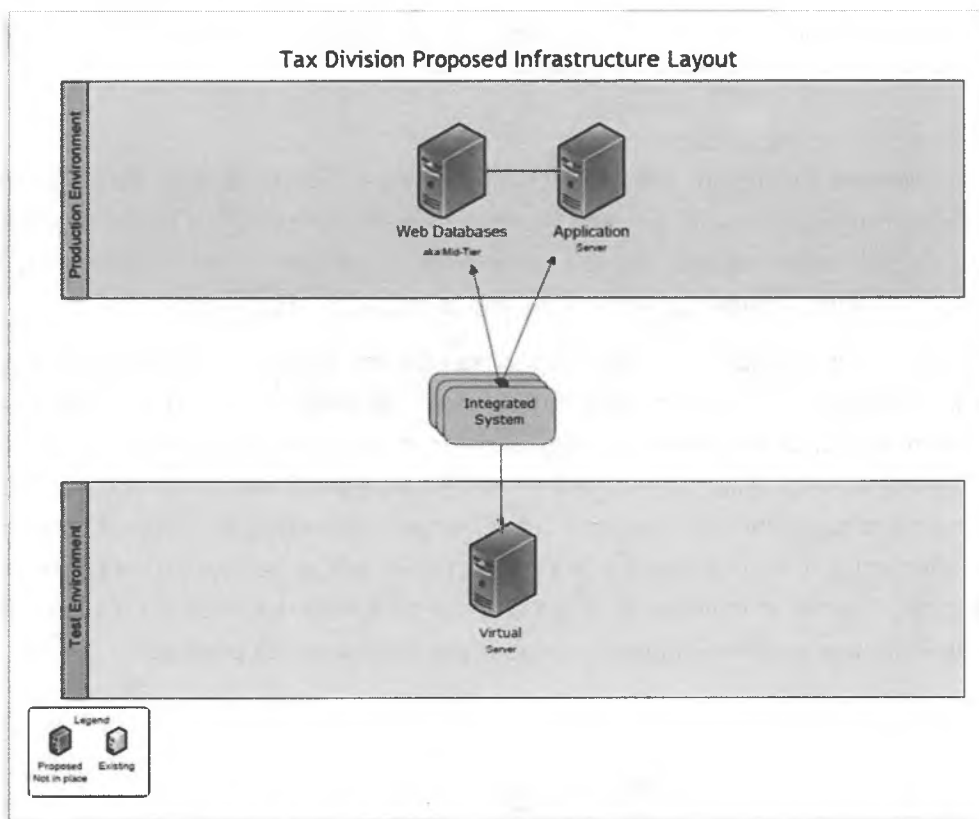
agency's ability to accumulate data from other government agencies and external sources to look for trends, improve forecasts, and increase compliance.

5. Streamlined System Maintenance

Multiple systems require a variety of skill sets for maintenance and development. An ITMS provides a single system with a common architecture and standard delivery platform. It is based on modern technology, so the skill sets needed to maintain and support the system are more closely matched with the education and training provided by universities and technical institutes today.

An upgrade to an ITMS would not only make users more efficient, it would also make technology maintenance more efficient. By being able to consolidate all of DOR/TAX's systems into one system, TAX is only responsible for maintenance of one group of servers, all using the same platform. Throttling can be used to move activity away from one server when service packs need to be applied or other maintenance needs to be performed. Dedicated development and testing environments can allow new development and testing to occur without affecting what users see in the production environment until it has passed testing. Server monitoring tools can give real-time statistics on server response times and be used to make sure the system is running as smoothly and efficiently as possible.





F. Benefits Realized in Other States

Benefits that have been reported by Montana, North Dakota, West Virginia, and Utah are summarized below. Vermont recently went into production and Arkansas' implementation is still in progress, so they have not yet reported benefits information attributed to their projects.

a) Montana

Between 2006 and 2008, the Montana Department of Revenue was able to increase collections from **\$40 million to \$58 million**, an increase of **\$18 million** or 45%. The agency attributes the increase to streamlining and automating the pursuit of routine debt while directing tax officers to focus on complex, high-risk cases assisted by risk assessment and case management tools and improved data accuracy. During the same period, office audit collections increased from **\$28 million to \$41 million**, an increase of **\$13 million** or 46%.

b) North Dakota

One year after completing their implementation project, the North Dakota Office of the State Tax Commissioner reported increased revenue collections of **\$7.6 million**. They attributed the increase to better tools enabling the prioritization of collection cases and improved audit selection.

c) West Virginia

Prior to 2007, the West Virginia State Tax Department's Compliance Division averaged annual enforced collections of **\$88.2 million**. Since 2008, the Division has averaged **\$130.7 million** in annual enforced collections, an increase of 48%. The Division attributes the increases to the use of collection case management and risk assessment tools. Also, they have been able to refocus employees who previously performed manual non-revenue generating tasks on collection efforts.

The agency also implemented a new tax discovery program using its data warehouse, matching state records with the Federal Individual Master File (IMF). The program brought in **\$460,000** in the first six months of operation.

d) Utah

The Utah State Tax Commission was able to increase individual income tax office audit assessments from **\$18.5 million** in 2006 to **\$28.6 million** in 2007, an increase of **\$10.1 million** or 55%. Recovery, as measured by assessments per hour, more than doubled, increasing from **\$500** to **\$1,010** per hour.

Withholding tax assessments directed at non-filers increased from **\$5.5 million** in 2006 to **\$12.8 million** in 2007, an increase of **\$7.3 million** or 133%. Recovery, as measured by assessments per hour, more than tripled from **\$768** to **\$2,312** per hour.

The Tax Commission attributes the increases to the use of analytical tools to select high-value audits. For both programs, the number of audits actually decreased between 2006 and 2007, but staff were able to focus their attention on more productive, high-value audits.

G. Funding Alternatives

Five different funding approaches are described for DOR/TAX consideration. While the most common model for public procurement is fixed price, other alternatives are available and some are being used for the procurement of an ITMS. Alternatives are briefly described below.

1. Fixed Price

A fixed price contract is one in which the price is preset and invariable, regardless of the actual costs incurred by the vendor. This approach is commonly used for public procurement in order to keep costs within a predetermined budget. The resources and hours that are required to complete the project may be greater or lesser than those originally estimated, but variations do not affect the amount paid to the vendor as long as the results (software, services, and artifacts, etc.) are delivered according to the terms of the contract. Changes in scope that mutually agreed on between the agency and the vendor may result in a change in the price.

2. Fixed Upper Limit, Time and Materials

This is a variation of the fixed price approach in which the vendor bills the client on a time and materials basis during the course of the project. If the hours and resources that are required to complete the project equal or exceed the original budgeted estimate, this approach is effectively equivalent to a fixed

price contract. However, if the required resources and hours are less than those budgeted, the project comes in under budget. The agency may have the option of investing the savings in additional functionality that may not have been in the project's original scope, or it may return the savings to the state. This approach was used by the state of Idaho in the procurement of its ITMS.

3. Proof of Concept

This is a cautious approach in which some aspect of a solution is tested on a pilot basis before a decision is made to proceed with the full project. For an ITMS project, it might mean putting a small number of taxes or some limited functionality into production before proceeding with the entire project. This approach is usually considered when there is a high degree of perceived risk and the jurisdiction is unwilling to fully commit funds until some element of success is demonstrated. Once the milestone has been reached and the jurisdiction is satisfied that the project's feasibility has been proven, the remainder of the project can proceed. If success is not demonstrated, the project can be abandoned or modified, and the jurisdiction's investment is minimized.

This approach was used by the state of Montana since the Department of Revenue's previous custom-build project was not successful and the legislature wanted to proceed with caution before fully funding another project. Five taxes were included in the proof of concept. Once they were successfully put into production within an eleven month period, the project continued with 47 additional taxes.

4. Benefits-based

A benefits-based project is one in which the procurement is funded from the additional revenues that are collected as a direct result of the project. The vendor is compensated as benefits are realized by the jurisdiction. This approach requires a well established baseline so that increases can be clearly measured.

Benefits-based projects will cost more since they entail greater risks on the part of the vendor. There are also cash flow considerations since the vendor will make investments up front but will not be compensated for them until sometime well into the project, or possibly even after the implementation is complete. However, there are advantages to this approach, particularly if budgets are tight and a project will not be authorized unless it is funded on this basis. The approach also ensures that benefits are received – if they are not, the jurisdiction does not pay the vendor for the project.

A number of different compensation models are possible. Compensation may be capped at a predetermined, fixed amount. Or, vendors may share in a revenue stream for the duration of the contract which means the greater the revenue stream, the greater the level of compensation. Compensation can be based on increased revenues, cost savings, or some combination of both. The agency's internal project-related costs are also taken into consideration and may be paid from the benefits received unless funding has been otherwise appropriated. It is important for the jurisdiction to plan for on-going system costs after the implementation project is complete and paid for.

To be successful, a strong partnership between the vendor and the agency is essential, and a mutual focus must be placed on achieving benefits. The agency needs to be prepared to step up and follow through on its commitment to increase revenues and/or achieve cost savings, recognizing there will be strong incentives on the vendor's part to generate benefits as early as possible. While a benefits-based project can produce other improvements such as enhanced taxpayer service, those will not be the primary focus of the project.

A jurisdiction will likely need explicit legal authority to authorize a benefits-based project.

This approach has been used by tax agencies in a number of jurisdictions both for compliance-related technology such as data warehouses and associated analytics, and for ITMS projects. States with benefit-based projects include Arizona, California, Hawaii, South Carolina, and Missouri.

5. Software as a Service

Software as a service is a relatively new concept sometimes called "software on demand" or a "hosted solution." Under this concept, the solution is deployed over the Internet via a web browser. Database and application servers are physically located at a vendor-maintained site. The vendor is responsible for managing and maintaining the server platforms and the application software, while the client is responsible for individual client workstations.

This option allows a jurisdiction to avoid upfront and ongoing hardware procurement and maintenance expenditures other than costs related to individual workstations. The vendor is responsible for procuring, managing, and maintaining the server platforms and application software, and for all server-side operations and activities such as day-to-day application and database software backup and recovery, database tuning, etc. The vendor provides support and maintenance for the deployed solution including new and revised documentation and defect repair, and addresses service pack analysis and installation as well as the installation and testing of new software versions.

One advantage of this approach is the opportunity for flexible pricing models such as subscription fees or charging per transaction. For example, the cost of hardware, software licensing, and configuration and implementation services, as well as on-going hosting, maintenance, and support could be included in a monthly, quarterly, or annual fixed subscription fee over the contract period (e.g. five years). This provides for stable and predictable payments over a period of time rather than having to finance a single lump sum upfront to cover the costs of a multi-year project.

VII. Implementation Roadmap

This section provides a roadmap for DOR/TAX as it prepares for an ITMS project. It focuses on activities leading up to two important milestones - the procurement process and the start of implementation. The selected business partner will work closely with DOR/TAX to plan many details of the implementation including the implementation methodology, project schedule, conversion approach, testing plan, and training approach. Nevertheless, this roadmap will identify factors contributing to a project's success irrespective of the chosen solution and business partner.

A. Preparing for Procurement: Activities Before the RFP Is Issued

1. Do Your Homework

As with any purchase, an understanding of the marketplace is critical to effective procurement of an ITMS. The rules associated with formal procurement processes often limit an agency's ability to carry out important research that is helpful to develop such an understanding. Some homework is in order before the issuance of an RFP imposes formal communication restrictions on the process.

Consider the following:

- Ask for vendor presentations and demonstrations
- Talk to (or visit) existing client sites:
- "Old" sites that have been in maintenance and support for a long period
- "New" sites that have only recently completed their initial implementation project
- "In progress" sites that are still working on their initial implementation project

As with any purchase, an understanding of the marketplace is critical to effective procurement of an ITMS.

2. Learn from Others

If there is a causal relationship between creating a good RFP procurement process and selecting a successful solution and business partner, then identifying states that have had a successful project and reviewing their RFP document and procurement process is useful. This will leverage the experience of others who have successfully procured and implemented an integrated tax solution.

Questions to ask about the procurement process include:

- Were there many vendor questions regarding the RFP?
- Could you have avoided those questions with further refinement of the RFP prior to issuance?
- How many amendments did you issue?
- In general, were you able to keep to your intended procurement schedule?
- Did you extend the due date? How many times? Why?

- Did the responses provide the information you expected?
- How difficult were the responses to evaluate?
- Was there a clear winner?
- Were there any appeals of the process or result?

Also, you can learn a great deal from those who have migrated taxes to production with an ITMS.

Questions to ask about the implementation project include:

- Did implementation proceed smoothly?
- Was your implementation on time?
- Did your project stay within budget?
- Did the scope expand during the project and, if so, why?
- Were there any difficulties with the vendor/client relationship?
- Did you feel as though the vendor was consistently acting in your best interest?

Questions to ask about the ITMS solution include:

- Did it meet your needs at implementation?
- Was it flexible enough to change as your needs evolved?
- Is there any reason to think you would have to eventually replace it?
- Is the solution expanding beyond its original scope?
- Did any difficulties develop with the vendor/client relationship after the implementation project?

Topics to address when asking about their selected vendor include:

- Reputation (i.e., credibility, stability, longevity, management credentials)
- Technical support (scope and responsiveness)
- Willingness to negotiate changes and number of change requests needed
- Training support
- Ability to integrate technological changes into the ITMS product

3. Choosing a Funding Approach

Consider the pros and cons of using different funding approaches including:

- Fixed price
- Fixed upper limit, time and materials
- Proof of concept
- Benefits-based
- Software as a service

These funding approaches are described in section VII. *Funding Alternatives*.

4. Choosing the Type of Solution You Wish to Procure

Various options are available to DOR/TAX for an ITMS including custom, transfer, and commercial off-the-shelf (COTS) solutions. These alternatives are described in section V. *Alternative Approaches*. You should select the type(s) of solutions you want vendors to propose for DOR/TAX's consideration and evaluation.

- If DOR/TAX is interested in a custom solution, it should consider first issuing a Request for Information (RFI) specifically inviting responses from vendors interested in proposing a custom solution for DOR/TAX. The RFI should request a company profile, information about the technology to be used, a system description, pricing and schedule information, the company's experience implementing similar systems in jurisdictions comparable to Alaska, and any other information DOR/TAX believes would be useful in evaluating the costs and benefits of further pursuing a custom solution.
- If DOR/TAX is interested in a COTS solution, they should issue an RFP specifying that responses must propose a COTS solution. In recent years, this approach was used in Arkansas, Mississippi, and Oklahoma.
- If DOR/TAX is interested in either a COTS or transfer solution, they should issue an RFP specifying that responses must propose a COTS or transfer solution. In recent years, this approach was used in Utah.

B. Writing the RFP

It is often considered a "best practice" to contract for assistance in preparing the RFP. In order to avoid a conflict of interest, common procurement practices typically prohibit the company that assists in authoring an RFP from responding to that RFP.

While you will want to rely on the professional expertise of the firm you engage for RFP assistance, some general guidelines are provided for consideration.

1. Structure and Content

Consider the following general guidelines:

- Mandate a uniform structure for the response. This allows you to compare responses directly, topic by topic, in order to determine relative compliance, responsiveness, and merit.
- Minimize "essay" questions. Invitations to "describe" or "discuss" can lead to lengthy narratives that are time consuming and difficult to evaluate while the evaluations themselves can be difficult to quantify.
- State the agency's expectations and invite the vendor to concur or to propose and justify an alternative.
- Identify areas in which the agency has some flexibility and ask for the vendor's advice and recommendations – for example, the implementation schedule.

- When seeking a COTS solution, avoid prescribing implementation methodology. The approach to implementing a COTS product differs from custom development.
- Work the evaluation of an oral presentation and demonstration into the final score of the response.

2. Reference Sites

Consider the following:

- Request references from previous clients that are similar to your agency in size and project scope.
- Consider requesting contact information for all of the vendor's client sites – not only those sites that the vendor lists as "reference sites."
- As you check on references, do not limit your questions to pre-defined, fixed questions. Give yourself the flexibility to follow up on information provided by the reference contact.
- Participate in onsite visits to reference agencies and discuss their solution and implementation experiences.

3. Show and Tell

The DOR/TAX project manager must organize a competent and knowledgeable project team of functional and technical subject matter experts to participate in the contractual process (i.e., vendor analysis, vendor demonstrations, and evaluation of proposals.) The project manager must work closely with acquisition staff to ensure that each vendor demonstrates, and can provide examples and references, for services and work products that are consistent with contractual obligations proposed and responded to in the RFP.

Consider the following:

- Include an oral presentation and demonstration in the evaluation process. This will allow the agency to see the product and the proposed team first hand.
- Provide in advance a list of business functions to be demonstrated by the actual, proposed project staff.
- Allow time for questions and answers. In addition to allowing for clarification, this will allow you to evaluate the vendor staff with whom you may be working.
- Decide how much weight to place on product demonstrations in the final score – actual demonstrations may be more important than what a vendor writes or says about their product

*Include an oral presentation and
demonstration in the evaluation process.*

4. Proposed Project Staff

Consider requesting resumes for key proposed staff such as project manager, application architect, training Lead, technical lead, and conversion lead. It is often difficult for a vendor to commit to, and provide resumes for, an entire project team. Consider the relative importance of experience and demonstrated success with the proposed solution in a tax agency vs. industry certifications (PMP, Microsoft, etc.).

5. Contract Terms

Consider the following:

- Include a sample contract. Ask for comments and suggested changes.
- Make terms and conditions reciprocal where appropriate (for example, relationship of parties, assignment, and confidentiality).
- Must all contractual issues be resolved at the time of the response submission? Alternatively, will the agency have the flexibility to negotiate the contract with the apparent successful vendor?
- Plan on entering into a long-term relationship with the vendor for software and services, such as ongoing software maintenance, new software releases, support, and other service

6. Financial Provisions

Consider the following:

- Deferred payment and bonding are forms of insurance. They increase costs to the agency, and it is important to ensure costs are not disproportionate to the benefit.
- Consider avoiding liquidated damages and indirect damages, and setting a reasonable limit on liability for direct damages.
- Liquidated damages and significant bond requirements can preclude some companies from even responding to an RFP.
- If a performance bond is necessary:
 - Subject only services to a bond; hardware, software license, and software maintenance should be excluded from bonding.
 - Stipulate that only a percentage of the service contract value be subject to bond – for example, 10% of the service contract value.
 - Tie the bond value to the value of the single phase of work in progress.
 - Permit the bond to take various forms (cash, letter of credit, surety).
- Consider a percentage holdback of payment until that phase of work is delivered successfully in lieu of a bond, but avoid combining a holdback with a bond – that is a form of double jeopardy with financial implications on the cost of the project.
- If a fixed price bid is being considered, avoid emphasis on consultant hours. Decide if the proposal needs to quantify project hours and require timesheets.

- Regardless of the funding model, consider a payment schedule that provides for progress payments based on project milestones.

7. Payment Schedule

Consider the following, especially for a COTS solution:

- Typical approach for one-time costs:
 - Initial license upon installation (for example, week two of the project)
 - Annual maintenance starts then and continues indefinitely
 - Services for each phase priced separately
- Two models for on-going costs:
 - Maintenance and support priced separately – lower initial cost, higher long term cost
 - Maintenance and support bundled - higher initial cost

8. Identifying requirements

When you are identifying requirements for a project, consider defining technical, functional, and management requirements.

a) Technical Requirements

Consider the following:

- When defining technical requirements, consider specifying that the solution is based on widely - used, non-proprietary, proven technology that has a solid history of upgradability.
- Consider whether you want to limit alternatives by specifying the programming language or other technical architecture components. There are many different and powerful technologies to choose from and this should not drive the business decision.

b) Functional Requirements

Consider the following:

- It is not feasible to develop an exhaustive list of detailed requirements across all the functional subject areas of an ITMS. Furthermore, it cannot be assumed that meeting every line item requirement in such a list – even if there are thousands – means that the solution is complete. The true measure of the completeness of an ITMS is the agency's ability to use it to administer tax without resorting to extensive manual processes, side-systems, and other software tools or products.
- The functional requirements list should be a yardstick by which solutions can be measured against one another. Therefore, express a reasonable number of requirements – enough to evaluate the solution but without exhaustively specifying it. Think in terms of 200-300 functional requirements not 2,000-3,000.

- Focus on business outcomes by clearly stating business requirements as a “what” without prescribing the “how.”
- Avoid open-ended requirements such as open-ended requirements such as “including but not limited to” and “must meet all current and future standards.”
- Avoid trying to eliminate your IT unit through requirements such as “must be able to change configuration without IT involvement” or “must be able to create report without IT involvement.”

c) Management Requirements

Consider the following:

- Clearly mandate conformance with state law, department regulations, and oversight agency policy and practices.
- If you are implementing a COTS solution, be prepared to manage an iterative process with minimal formal signoffs and occasional “rework.”
- Avoid specifying an implementation methodology, if you are implementing a COTS solution, most have methodologies that are designed for the product. Allow for alternative approaches, but make the vendor prove that the alternative has worked elsewhere.
- Decide whether to dictate the schedule, phases, and length of contract. If there is flexibility, allow the vendor to propose an approach.
- Limit paper deliverables to those required to know the project is on track and successful. Project integrity is often hindered when too much emphasis is placed on document development rather than system implementation.

9. Technical Platform

It is important that the platform be:

- Based on mainstream technology
- State-of-the-art and not at end-of-life
- Economical to acquire and maintain
- Pervasive in the industry to ensure availability of replacement parts and support resources
- Designed to meet the load and performance requirements of the solution

10. Functionality

Consider the following:

- Be precise about the meaning of “mandatory.” Will not meeting a single mandatory requirement result in disqualification?

- For a COTS solution, the use of response categories for each function can assist by defining if the capability:
 - is in the base product and configurable “out-of-the-box” (requires no programming);
 - will be supported by site-specific (custom) programming;
 - will be supported in a future release of the product - should the new function be in beta test and demonstrable to qualify for this response?
 - is not directly supported by the product but will be supported through an interface to, or use of, other software; cannot or will not be supported.

11. Methodology

Ensure that the proposed methodology has been employed successfully (i.e. on time, on budget) to implement the proposed software for integrated tax administration for an agency of similar size and complexity.

Avoid an overly rigid scoring process. This can lead you to a vendor that looks good on paper but cannot substantiate its cost and experience claims.

12. Current Install Base

Require that the proposed solution has been in production for integrated tax administration for an agency of similar size and complexity for some minimum period of time, such as two full agency business cycles.

13. Vendor Record of Accomplishment

Require that the vendor and particularly the proposed key resources have implemented the proposed solution for integrated tax administration

for an agency of similar size and complexity using the proposed methodology.

14. Vendor Financial Stability

Require that the vendor provide recent financial statements or other proof of stability.

15. Price

Consider a “best value” approach as an alternative to “low cost” when developing the scoring method. A best value approach is based on the combination of technical score and cost score.

16. Evaluation Approach

Avoid an overly rigid scoring process. This can lead you to a vendor that looks good on paper but cannot substantiate its cost and experience claims.

C. Alternate Method

The Oklahoma Tax Commission is using the Performance Information Procurement System (PIPS) in their current procurement process for an ITMS. PIPS is described as a “best value” selection and management process that can be used to purchase any type of product or service. The process provides clients with a tool to assist them in making an informed decision based on performance information and not based solely on price or marketing information. The process has a mechanism to document and manage the vendor/service during the project.

D. Preparing for the Project

1. Creating a Project Team

- Select a Project Champion - an agency executive or senior manager whose role is to promote the project both within and outside the agency including stakeholders who may be impacted by the changes. The Project Champion acts as the “cheerleader” for the project.
- Select a Project Sponsor - an agency executive who can provide high-level direction to the project and assume responsibility for approving all significant decision requests. The Sponsor also acts as the final level of issue resolution within the project.
- Establish a Steering Committee - comprised of senior user management and the project directors from both agency and vendor side. This committee assumes responsibility for deciding management, policy, and directional issues that affect the project, primarily from external sources. This committee should meet on a regular scheduled basis to discuss options, issues, and areas of concern. This forum also provides a venue to demonstrate new or upcoming project changes.
- Select a Project Communications Coordinator - Consider appointing a Project Communications Coordinator very early in project planning with the responsibility and authority to communicate the progress, needs, and accomplishments of the project. A critical task of this role is to inform staff and stakeholders of the project’s progress and facilitate the flow of information for decision making. From time to time, the project Communications Coordinator will involve staff and other stakeholders to contribute.
- Consider an Independent Project Manager - An independent project manager can provide the link between the project stakeholders and vendors that will undertake the work. Additionally, the independent project manager will work with the vendor’s project manager to form a team responsible for providing management of integration, scope, time, cost, quality, human resources, communication, and risks for the project.

2. Creating a Partnership Approach

In many implementations a “partnership approach” to project staffing is desired - some states have made this a requirement of the successful vendor. This approach helps ensure project success and incorporates good practices, into processes and plans and provides the basis for effective knowledge

transfer. The close day-to-day working relationship, between DOR/TAX and the vendor, should enable joint management and control of the project, manifested in several key areas:

- Support the open, unrestrained, and frequent exchange of information and ideas. This promotes efficient communication between the vendor's team and DOR/TAX representatives, stakeholders, and sponsors at the various organizational levels.
- Encourage direct participation by the DOR/TAX management team and stakeholders at meetings, status reviews, planning sessions, and via oversight activities.
- Invite the active participation and involvement of DOR/TAX managers in the measurement and control of risk and the resolution of problems and issues.
- Encourage active participation by DOR/TAX users in the development of testing plans, test material development, and actual testing to ensure we address actual user perspectives
- Ensure active participation by DOR/TAX technical staff (developers, support, and operations) in the installation of the environments and the development and configuration of the solution

DOR/TAX can begin planning and executing a data cleanup strategy immediately, even before an RFP has been issued and well before an implementation project begins.

DOR/TAX should require the successful vendor to align their working hours and holidays so the vendors are available to support DOR/TAX throughout the project. Additionally, because of its unique geographic location DOR/TAX should require the vendor to have a full time presence in the state during project implementation. Time lost due to fly-

in/fly-out days prevents successful communication and does not provide responsive information exchange, effective executive oversight, or coordination with third-party vendors, user communities, or other stakeholders.

3. Preparing Data

Many revenue agencies contemplating a new ITMS are currently working with a suite of applications that are up to 30 or even 40 years old. Most of these applications outgrew their flexibility and expandability many years ago. Relaxed business rules representing the lowest common denominator of data edits may have resulted in inconsistencies, redundancies, and generally poor data quality overall.

The first step to prepare for conversion into a new system is to understand your data resource. The first step in doing that is to determine where to find the profound data resource knowledge. This may be in written documents but, all too often, written material is incomplete and out of date. Your best data resource information may come from your people.

DOR/TAX can begin planning and executing a data cleanup strategy immediately, even before an RFP has been issued and well before an implementation project begins.

Data cleanup should take a “work smarter, not harder” approach. Not all data needs to be cleaned - only the data that is likely to be converted. Two factors can help to determine what to clean:

- How old to convert, as governed by both statute and practicality?
- Which is the best source of redundantly held information?

Start by identifying the best sources, for example, where is the best address information, and cleaning the most current information in those sources. Automated means are preferable, but manual means may be necessary.

In addition to improving the data quality, the analysis needed to drive a cleansing process will be helpful in the conversion phase of a new system implementation. Time spent in reconnaissance is seldom wasted.

4. Determining the Location of the Project

One issue somewhat unique to DOR/TAX is that key employees needing to be involved in the day-to-day decision making during the implementation project are split between two locations, Juneau and Anchorage. This includes users who specialize in the same tax program and in some cases the same functional area. DOR/TAX needs to determine if the project staff will primarily be located in Anchorage, Juneau, or whether the project can operate with employees located in each of the two cities. The overriding issue to consider when making this decision is “What is the best location to ensure a successful project?”

When determining the project location, factors that should be taken into account include:

- Decision makers involved
- Staff buy-in to project decisions
- Interaction between project staff and system users
- Users and project staff needs for relocation or travel
- Communication capabilities between project staff at the two locations
- Strategy for knowledge transfer

VIII. Project Management Plan

This Project Management Plan (PMP) establishes the framework necessary for the execution of the procurement and configuration of a new ITMS for DOR/TAX. When fully populated, this framework for a PMP will outline the project scope, budget, configuration, resource requirements, and responsibilities necessary. This PMP will also outline the technical performance requirements for the management and control of the project from initiation through final delivery. The plan provides performance measurement criteria including major milestones. This PMP should be a living document subject to change as conditions warrant, or as project experience dictates.

A. Integration Management

1. Develop a Project Charter

DOR/TAX developed a project charter in 2008.³

2. Develop a Project Management Plan

This document serves part of that need as it begins to document the actions necessary to define, prepare, integrate, and coordinate a successful implementation of an ITMS.

3. Direct and Manage Project Execution

The process of tracking, reviewing and regulating the progress of the project to meet the objectives of DOR/TAX will be the responsibility of the project management team. DOR/TAX can make the team management selections mentioned in the previous section of this report before funding approval. DOR/TAX may also want to consider hiring an independent project manager.

Technology projects are high cost and high-risk endeavors. There are many examples of highly publicized failures. The successful projects have a number of things in common, one of which is a cohesive approach to overall project management.

Projects in Colorado, Idaho, Louisiana, Maine, Montana, North Dakota, and Utah employed an independent project manager with good results.

Projects in Arizona, New Mexico, West Virginia, and Wisconsin, have been successful without an independent project manager because the agency was able to dedicate and appoint talented resources from their own staff.

³ Refer to the attached *Project Charter* for more information.

Some public sector agencies do not have personnel with proven project management skills or are unable to devote someone with the appropriate skills to the day-to-day details of coordinating a major technology implementation. Utilizing an independent project manager to provide professional project management services can add value to the overall execution and help ensure the success of an ITMS.

An independent project manager can provide a broader perspective from their exposure to similar projects. They can bring a working knowledge of proven project management methodologies and tools, system implementation strategies, and project risks. Hiring the right independent project manager with revenue system experience will bring an understanding of how ITMS implementations affect agency business processes, organizational structures, and resource requirements, enabling the project manager to help balance project needs with the continuing day-to-day activities of the agency.

A key benefit of using an independent project manager is the unfettered viewpoint they provide. They focus solely on the project, with no conflicting responsibilities within the agency. They have no organizational bias and are thus able to mediate controversial issues without fear of burning political or organizational capital. They are also independent of the system vendor, so they can provide an objective evaluation of status, help control project scope and manage change, and facilitate decision making. This independent viewpoint helps enable both the agency and the system vendor to focus on what they do best without distraction. Additionally, it facilitates the interaction between the agency's users and the vendor's project staff and provides an added level of confidence to outside stakeholders.

All projects involve change. Change management does not happen without a major change effort occurring in the organization.

4. Perform Integrated Change Control

All projects involve change. Change management does not happen without a major change effort occurring in the organization. Success of that change effort depends on a well-planned, well-executed, implementation program that prepares and enables stakeholders to utilize the new technology and adapt to the new work processes.

a) Sources of Change

Issues arising on the project normally take one of two forms, issues with differences in configuration and functionality or issues with and between personnel. Project management will concentrate on issue resolution at the lowest level and encourage open and effective communications between and within all levels.

The selected vendor should provide evidence of a method of managing changes to functionality in order to assist in scope management and provide a communication medium for the change. Subject matter

experts, team leads, and project managers must be empowered to devise solutions, present viable solutions for consideration, and make recommendations for change to ensure project success.

Not all people think alike. Expect differences in opinion, and celebrate the value different viewpoints bring to the project. Diversity of perspective can lead to a better result. It is only when the differences begin to adversely affect the project or take on a personal nature that intervention by the project management team becomes necessary. The vendor should strive to ensure all communications remain professional by providing team-building opportunities, learning opportunities, and issue resolution channels, thereby establishing a professional yet fun workplace early, and continually, throughout project execution.

b) Change Management Plan

DOR/TAX should ensure the successful vendor has a plan for both functional and/or configuration change management and business process change management.

The goals of a Change Management Plan are to:

- Facilitate the successful implementation of the ITMS
- Help DOR/TAX management anticipate issues, improve their change leadership skills, and manage risk related to the DOR/TAX staff's ability to adapt project-initiated changes
- Provide a framework for DOR/TAX to address the organizational changes resulting from this project

Normally, a project incorporates a Change Order process for situations in which the contemplated change will have a cost and schedule impact. Some non-cost and non-schedule decisions can be made informally by agency staff and management assigned to the project or within the executive oversight group. Between the two extremes of informal decisions and formal Change Orders, a Decision Request process can be helpful.

Specified in the Change Management Plan, Decision Requests are an established method of raising project scope problems, questions, or concerns in a timely, concise, and consistent way. Not all issues that come up during the project rise to the level of a Decision Request. The vast majority of issues will be resolved by the project team during the course of the project. For issues not resolved on the shop floor, a structured decision process with a Decision Request Form and associated procedures helps ensure the issues are presented to management in a complete and concise fashion. The issues are tracked through the decision-making process until resolved.

Additionally, a Decision Request Form helps ensure the team presents issues to decision makers in a complete and concise fashion. The form directs staff to include the issue origination date, the decision needed by date, and the project priority level. A Decision Request Form in conjunction with the Decision Request log tracks a decision from inception until resolution and serves as a historical archive for the project. When implementing a COTS product, for example, decision requests may take one of the following paths:

- Issue is determined a project issue
 - and is resolved internally by new, changed, or standardized business process.
 - and is resolved by a change in configuration (results in a Change Request).
 - and is resolved by a change to code (results in a Change Request).
- Issue is determined not a project issue and is resolved by changed communications.

Using change management techniques, communicated in a change management plan, DOR/TAX will be able to transform their current processes, technology, and work environment. With leadership forging the way, along with an involved group of stakeholders, an organization can manage and lead change effectively.

Human resource processes such as new organization design, job design, selection and performance management systems must be aligned with the future workplace to sustain lasting change. Technology can assist. In the course of preparing this project, it was noted that current performance metrics do not adequately provide clarity for managers nor do they provide adequate goals for the staff. The current performance measures are limited by the current technology.

These are ten common barriers to change which must be understood to successfully develop activities to avoid these challenges:

- Resistance to change
- Inadequate sponsorship
- Unrealistic expectations
- Poor project management
- Case for change not compelling
- Project team lacked skills
- Scope expansion
- No change management process
- No horizontal process view
- IT perspective not integrated

Employee resistance to change, inadequate sponsorship at the leadership levels, and the inability to manage expectations typically are the greatest challenge, especially if the overall program does not include strategies and actions to minimize these barriers. In addition, the lack of a developed case for change without a change leadership program makes it difficult for an organization to successfully transition.

The remaining barriers, team skills, scope expansion, no horizontal process view, and the IT perspective not integrated, are addressed through strong program and project management. A key message is that along with other important project areas, change is a significant component that must be planned and managed to successfully implement technology projects.

To obtain the goal of efficiency, DOR/TAX will need to build in transparency, create a flexible organization, and foster a culture that supports agency-wide teamwork, while maintaining individual accountability. To achieve this goal, DOR/TAX will need to review its organizational design and be open to job reclassification.

c) Business Process Reengineering

Installing an integrated tax solution is primarily a business process reengineering project. The solution incorporates and supports “best practice” tax administration, providing a suite of integrated tax functions that are designed to work together in a particular way. In addition to configuring the agency’s business rules into the solution, the agency must “wrap itself around” those functions.

Throughout implementation and afterwards, opportunities for business process improvement (BPI) will surface. The new system will provide capabilities that were not previously available or it will simply take a different approach that supports streamlined business procedures. Occasionally, BPI opportunities will spawn or enable organizational changes – some of which may have been long contemplated and some which are newly devised.

While the agency should embrace these BPI opportunities, it is prudent to take a measured approach. Wholesale “boil the ocean” BPR and organizational change can actually hinder, or even endanger, an implementation project depending on an organization’s capacity.

B. Scope Management

It is a natural tendency of internal stakeholders (and sometimes developers) to pile on additional requirements and enhancements that often substantially increase project risk, time, and/or cost. Effective control of the project scope involves collecting requirements, defining the scope, creating a work breakdown structure, verifying the scope, and controlling the scope. The independent project manager or state project manager in association with the vendor’s project manager and the concurrence of the Project Steering Committee must have the ability to manage scope throughout the life of the project.

1. Collect Requirements

This report, combined with the previous research and studies performed by DOR/TAX since 2007 have provided a rich source of information that taken together can form the basis of the high level requirements for this project. The requirements will need further refinement, weighting, and revision for inclusion in a future RFP.

Requirements for a new tax system should include the following functional areas:

- Entity creation and maintenance
- Payment processing
- Returns processing
- Return issue / license renewal
- Non filer identification and processing
- Gap filer identification and processing
- Taxpayer transactions processing
- Refund processing

- Collections and compliance monitoring
- Taxpayer correspondence management
- Internet services for taxpayer self-service
- Integrated security
- Integrated reporting, OLAP cubes, analysis tools
- Integrated Imaging
- Revenue fund management
- Shared taxes processing
- Audit functionality and management
- Appeals case management
- Data capture and imaging support
- Integrated workflow management
- Data warehouse storage and management
- General case management
- Inventory management
- Interface capability

2. Define Scope

According to *In Search of Excellence in Project Management* (Kerzner, 1998), the scope statement becomes the basis for all future project decisions. Therefore, a clear understanding of project scope, its definition, and the manner in which scope changes would be implemented into the project is key to project success. Kerzner (1998) states, "Scope definition is extremely important to the success of any project" and "Scope 'creep' and scope 'leap' are often the root cause of project failure" (p. 13).

DOR/TAX defined the scope for this project in their *New Tax Revenue Management System: Project Charter* (ADOR/TAX, 2008) as follows:

"A complete integrated tax processing software package, designed to support the Tax Division with the management of multiple taxes and licensing, and associated business and processing rules, with minimal changes to the program code – and meets state IT standards and federal (IRS) security standards. The package will support configuration covering almost all aspects of the system including returns, letters, penalty, interest, transactions (financial and non-financial) customer demographics, workflow, terminology and a robust user interface" (p. 5).

The scope of the ITMS project should contain the following components:

- Project management
- Implementation of the ITMS
- Implementation of hardware, software, and network infrastructure
- Conversion of legacy data
- Business process reengineering support
- Training of users, IT support staff, and management
- Documentation of site-specific procedures, processes and changed functions
- Post-implementation maintenance and support

The scope of the ITMS project should include all the functional activities for the following tax types:

- Oil and Gas Production
- Oil and Gas Conservations Surcharge
- Oil and Gas Property
- Corporate Income
- Tobacco
- Motor Fuel
- Alcoholic Beverages
- Commercial Passenger Vessel
- Large Passenger Vessel Gaming
- Vehicle Rental
- Tire Fee
- Mining License
- Fisheries Business
- Fishery Resource Landing
- Seafood Marketing
- Salmon Enhancement
- Seafood Development
- Dive Fishery Management
- Telephone Cooperative
- Electric Cooperative
- Gaming
- Estate

3. Create a Work Breakdown Structure (WBS)

Creating a WBS is the process of subdividing project deliverables and project work into smaller more manageable tasks. This report, building upon the previous work DOR/TAX performed, begins the process of creating a WBS by defining the objectives of the proposed ITMS project follows:

- Replacing all 17 official systems and over 100 MS Excel spreadsheets in side-systems, with one integrated system. Current legacy systems will be retired as the tax types they administer are integrated into the new system.
- Migrating all 22 tax types to a new ITMS better capable of serving the needs of Alaska's taxpayer base. The results of this project will provide for the technical and functional requirements of the identified taxes administered by DOR/TAX.
- Providing the ability to quickly adapt the tax types to the State's ever-changing tax laws and regulations
- Cleaning and preparing data for conversion from existing legacy systems
- Training users and operators to fully utilize system functionality
- Interfacing with current and new e-filing programs, including MeF
- Increasing compliance functions including non-filer, collections and audit
- Providing for data warehouse and integrated imaging capabilities
- Automatic distribution of shared taxes after user approval
- Configuration development that meets the State of Alaska and DOR's specific requirements while at the same time investigates potential process changes to improve efficiency and fairness.

Along with replacing the numerous MS Excel side-systems used to administer DOR/TAX's 22 tax types, work tasks during the project would also involve replacing and retiring existing legacy systems. TAX has identified the following systems for replacement with an ITMS:

• CPS	• Fish and Game License Application
• TAS	• Interest Engine for TAS
• DEE Excise	• UP Viewer
• DEE Motor Fuel/Corp	• Travel Document Image Viewer
• ASPR	• Oil and Gas Production Tax MS Access Databases
• OTIS	• Online Public Reports and Queries
• OPAL	• Gaming Stamp Manager
• OVR	• Petroleum Property Tax Application
• EMR	

4. Verify Scope

DOR/TAX will perform this step when formally accepting the list of deliverables.

5. Control Scope

The project management team will control the scope by measuring, monitoring, and reporting on project metrics throughout the project. Project performance measures will assess the variance from the originally determined scope when requests for changes arise. When change happens, the project management team will update the associated project documents and stakeholders will receive communications that reflect the change.

The requirements documentation will form the basis for the scope. The team will use one or more of the following methods to track the variation from the base scope:

- Work completed vs. schedule
- Cost vs. budget
- Performance vs. expectations
- Open issues review
- Updated risk assessment

C. Time Management

1. Define the Activities

The WBS developed during scope development will aid in creation of the work packages necessary to accomplish the objectives envisioned. The project management team will perform this step during the initialization phase of the project.

2. Sequence of Activities

Once all the activities are known, the project management team will sequence the specific activities necessary for completion of the project. One of the important decisions to make for this type of project is which tax type(s) to implement first. This is a decision that will need inputs from the vendor, the independent project manager (if one is used) and the units involved. Factors that can influence the decision to implement one tax before the other are:

- Current processing capability
- Expected changes to legislation
- Current hardware limitations
- Due date for tax types
- Group readiness, or personnel availability, and impact on current group workload
- Other taxes implemented at the same time

3. Estimate Activity Resources and Durations

In finalizing the schedule during project initialization, the project management team will need to take into consideration the resources from the vendor and the user groups. These kinds of projects require

coordination with SMEs, project management, and developers to ensure testing, training and phases of implementation happen at specific points in the schedule.

4. Develop the Schedule

The project management team will develop an estimated project schedule prior to the project kick-off meeting. The schedule may be revised as situations dictate during implementation. However, projects tend to finish on time when the schedule is a driving factor and everyone is dedicated to meeting the schedule. The schedule will contain milestones for deliverables, wherever applicable. DOR/TAX developed a primary sample schedule in 2009 as a representative project schedule. Although envisioned as a 5-year plan, the project might be completed sooner depending on resources and requirements. DOR/TAX should allow the prospective bidder to propose a project schedule that meets the division's baseline criteria. The proposed schedule created by DOR/TAX is shown in the *TRIMS* (ADOR/TAX, 2009) report.

5. Control the Schedule

After the Project Management Team develops the project schedule depicting interrelationships of tasks and activities, milestones and durations the team will then implement the schedule and begin to manage and monitor the schedule to ensure project completion.

During implementation while reviewing progress reports and reports of other performance measures the Project Management team will forecast changes necessary to the schedule. When forecasts indicate a need to change, the team will assess those changes against both the schedule and the scope.

One of the best methods to ensure the control of the schedule is to ensure all stakeholders stay informed of issues relating to that schedule. In this instance, communication is the key to an effective schedule.

D. Cost Management

The cost section of this report provides alternatives, estimates, and comparisons for funding, costs, and methods used to pay for an ITMS project. When DOR/TAX and its funding authorities make those determinations, the project management team will be the key leaders to ensure the project stays within the budget. Some of the techniques the project management team will use to control costs are:

- Ensuring that all change requests are acted upon in a timely manner
- Managing changes when they happen
- Monitoring work performed

E. Quality Management

Providing a quality product on schedule and within budget is the primary objective of all team members. DOR/TAX must ensure the selected vendor has a plan for testing and metrics for quality control. DOR/TAX must measure quality by the degree in which the vendor meets the requirements and provide

feedback quickly and accurately. The project management team must insist on meeting project objectives in such a way as to:

- Prevent overworking the project team
- Provide enough time and resources to adequately detect errors early in the process

Quality principals from the *PMBOK Guide* (Project Management Institute [PMI], 2008) stress the following:

- Customer satisfaction: For this project, customer means all stakeholders including DOR/TAX users, managers, and taxpayers. The stakeholders must be able to notice a change for the better.
- Prevention over inspection: The vendor must employ quality methods, using verifiable tools and metrics to ensure they design and build a product with quality in mind.
- Continuous improvement: The selected vendor must learn and adapt and so must DOR/TAX. These projects are all about change and improvement of the current state. All changes should measure up to improvement.
- Management responsibility: Success in these types of projects depends heavily on management involvement. Even if DOR/TAX elects to hire an independent project manager, the management responsibility to provide quality people, quality advice, and prompt decisions to the project remains.

F. Human Resources Management

The processes described in this plan supplement existing regulations for establishing more detailed and specific relationships among stakeholders participating in this project.

1. Develop Human Resources Plan

In the 2008 project charter, DOR/TAX identifies specific individuals, the skills, and the roles necessary for the project. In some implementations, the personnel dedicated to the project change positions within the organization and their previous positions remain unfilled for the duration of the project. In other organizations, the people move back to their previous positions upon project completion.

Before the project begins, and before assigning personnel to the project DOR/TAX should determine:

- Who will project members report to?
- How will the assignment to the project affect positions?
- What happens when the project ends?

One of the most critical roles on an ITMS project team is the SME. These projects are often more of a business process redesign than a technology upgrade. That makes the expertise of a SME a valuable and essential resource worthy of close management. Some key considerations for SME management follow:

- Trust is an important selection criterion for a SME. Often the agency knows they selected the right person from the unit if it is painful to give them up for the project. The sacrifice of valuable

resources made during project execution will make a huge difference. The SME needs to be trusted to make good decisions and have the backing of their management in order to be successful.

- A SME's responsibility is to represent accurately their business units' needs to the Project Team, and to validate the deliverable. SMEs also carry information about the project back to their user community and assist with effective communications to other stakeholders. During each rollout, SMEs will test the product and perform tasks normally performed by the user community. SMEs are often the best source of feedback to the project team.
- SMEs should be co-located with other project team members to ensure day-to-day contact and effective knowledge transfer. SMEs co-located on to the shop floor often learn more about the agency and are exposed to all aspects of the system. Skills of SMEs often expand beyond their previous legacy job description.
- Often, at the close of a project, the SMEs receive recognition as system experts, and provide a very valuable resource to the agency. Proper planning, early in project implementation, for post-project usage of the SME's skills is essential to maintaining them as a resource long into the future.

2. Acquire Project Team

Another important consideration is the on-boarding of project team members. When team members join and leave the team has significant impact on the project and the implementation. Key members such as the project managers and leads should begin and end the project to maintain continuity throughout the implementation. SMEs can join the project and leave the project when it moves into areas outside their expertise. The human resources plan created by the project management team prior to the kick-off meeting should communicate to all stakeholders when the project will need certain members for the project.

3. Develop Project Team

Our experience has demonstrated co-location greatly facilitates involving business experts not otherwise assigned to the project in the discussions and decisions related to the new system. Co-location also facilitates team interaction, improves the competency of individuals, and enhances the project performance. DOR/TAX should also work with the selected vendor to:

- Ensure developers have or obtain the minimum qualifications for the technology used
- Establish conditions to allow effective knowledge transfer
- Provide numerous and varied opportunities for learning new processes and procedures

4. Manage Project Team

Effective communication will assist in managing team performance. Providing feedback, and being proactive when issues arise, will optimize team performance and help to ensure success. The project management team will establish project standards to influence the project team and set professional and ethical standards.

G. Communication Management

Effective and appropriate communication is the key to an efficient organization. Furthermore, effective communication is important to the successful delivery and completion for DOR/TAX because it helps to align everyone to a common goal. Throughout implementation, clear and timely communications will help ensure DOR/TAX has the information required to make informed decisions on the implementation. It will also help to ensure the user community not only adopts but also welcomes the new system.

Another purpose of communication planning is to ensure the core and extended project team members develop an effective communication strategy for affected stakeholders. Important to the project communication strategy is identifying key stakeholders, developing accurate and consistent messages, and delivering the messages effectively. Successful project team communication depends on all core and extended project members playing a role and taking personal responsibility in the messages they deliver.

Effective, comprehensive, and coordinated communication is also a fundamental component of sound project management. Accordingly, developing and executing a thorough communication plan is a critical success factor in implementing a new system.

DOR/TAX should ensure the selected vendor proposes a coordinated communication plan used to identify communication targets and sources, messages that will satisfy the informational needs of those targets, messages that DOR/TAX need to hear from its sources, and the most effective methods for delivering and receiving those messages.

H. Risk Management

According to the *PMBOK Guide* (PMI, 2008), project risk management comprises the processes concerned with identifying, analyzing, and responding to project risk. It includes maximizing the results of positive events and minimizing the consequences of adverse events.

The processes include:

- Determining risks likely to affect the project and documenting the characteristics of each
- Evaluating the risks and risk interactions to assess the range of possible project outcomes
- Defining enhancement steps for opportunities and responses to threats
- Responding to changes in risk over the course of the project

1. Identified Project Risks

When embarking on an integrated tax management project, DOR/TAX leaders will face several risks and challenges. One of the major risks to an implementation project is the desire to replicate exactly all functions previously performed in legacy systems. Working together the project manager team with the advice of the SMEs and the Team Leads can usually come to an agreed upon solution that provides the functionality necessary for users to be productive.

Other risks to the project include:

- Assisting managers of affected areas in balancing productivity while transitioning between legacy and the existing standalone applications to the new environment
- Finding the right way to involve everyone in the organization in the project
- Carefully monitoring and attending to the redirection needs
- Focusing on creating the new environment
- Defining the staffing requirements
- Developing and implementing policies to meet those needs
- Maintaining positive moral and helping the DOR/TAX staff transition from the legacy systems to the new ITMS

2. Risk Mitigation

To mitigate project risks, the project management team must develop a risk management plan as a subset of the project plan. The plan must identify and document the risks that are likely to affect the outcome of the project. The managers must also be able to evaluate and quantify each risk and assess the range of possible outcomes. In other words, the managers must be able to distinguish between high-risk problems and low-risk problems. In many cases, the risk may not warrant a response, but when the risk is significant, the managers must be able to develop a risk response plan and take the necessary actions to mitigate the risks in accordance with the risk management plan.

There are steps DOR/TAX can take during the procurement and planning stages to minimize risk. Among these are seeking a proven solution, seeking a proven vendor, seeking a proven approach and planning for risk management during the project.

a) Seeking a Proven Solution

Reviewing information technology implementations in general and tax systems in particular, the research history shows IT projects fail to meet expectations because the solution does not match the problem.

For an ITMS to qualify as “proven,” consider the following requirements:

- The solution should be in production and operating for at least two complete fiscal business cycles (typically, two years).
- The solution should be in production at multiple tax agencies of similar size, complexity, and legislative framework.
- The solution should perform the core tax administration functions, including registration, returns processing, payment processing, accounting, refunds, collections, debt management, filing and payment compliance, audit, and revenue accounting.
- The solution should offer integrated supporting functions such as division-wide communications, security, workflow, imaging, correspondence, reporting, query, data analysis, data warehouse, data mining, leads management, and taxpayer self-service.

- The solution should perform the above functions for multiple tax types, including *all* of the major taxes and *most* of the minor taxes performed by DOR/TAX.
- The solution should be upgradable, extensible through configuration, and not at the end of its technological life-cycle.

b) Seeking a Proven Vendor and Approach

To qualify a proposing vendor as “proven,” consider requiring the vendor has a proven record of accomplishment on multiple successful implementations using the proposed software for integrated tax administration and using the proposed implementation methodology.

c) Managing Risk during the Project

Project risks are uncertainties or vulnerabilities that may have an adverse effect on the project. Since every project carries some element of risk, it is important to manage risk proactively and through a well defined risk management process.

The risk management process seeks to minimize the impact of unplanned incidents on the project by:

- Identifying potential risks
- Analyzing risk characteristics
- Developing risk mitigation strategies
- Continuously tracking risks and mitigation strategies until danger has passed

The project’s risk management plan should include the following:

- Roles and responsibilities of the participants
- Monitoring and control
- Escalation
- Risk analysis – a typical risk management matrix:
- Identification – What is the risk?
- Trigger – What is the event (if any) that could trigger the risk?
- Timeframe – When is the project exposed to the risk?
- Probability – How likely is the risk trigger to occur?
- Impact – What is the consequence of the risk?
- Severity Matrix – How will that consequence affect the project?
- Response Planning – What can be done to mitigate the risk?
- Contingency Planning – What can be done to recover from the consequence of the risk?

I. Implementation: Factors Leading to Success

In our experience, there are certain contributing factors that can greatly influence a project's outcome. Those that are within the influence of the agency are discussed below in terms of:

- Leadership support
- Staffing support
- Logistic support
- Technology support

1. Leadership Support

Activities in this area help leaders manage the change more effectively. Leaders must set focus and commitment, and create inspiration for people to change. Given that, leadership needs to commit to specific roles, responsibilities, and actions to lead the change initiative.

The following addresses leadership alignment and actions:

- Leadership alignment that ensures the leadership team embraces and commits to the vision of change - same goal, direction, and talk.
- Leadership action that focuses on encouraging the leadership team to develop tangible action plans and execute these plans to support change.
- Leadership management that sets direction, defines culture, and establishes structures and processes

As a result, it is critical to the success of the project that key decision-makers and top leadership remain engaged in the project through its completion.

The installation of an ITMS is a significant task. Inherent in any system change of this magnitude is a myriad of reactions to those changes within DOR/TAX. As a result, it is critical to the success of the project that key decision-makers and top leadership remain engaged in the project through its completion.

Leadership must make a clear and frequent message throughout DOR/TAX that the initiative is critical to the future success of the organization. At project kick-off and subsequent milestone events, DOR/TAX executives should deliver supportive acknowledgements to their employees. It is helpful for the leadership to discourage actions that undermine the project team's efforts such as unfounded negative comments.

In order to keep moving forward and on-track, DOR/TAX must make decisions timely. Our experience has shown that there must be a process in place for effective decision-making, and there needs to be

one person involved with the project who has authority to make decisions when there is a stalemate on a critical decision point.

One of the significant contributors to project failure is uncontrolled expansion of project scope. It is important for everyone to support fully the notion that the project's primary responsibility is to get the agreed-upon components of the project completed first.

Adherence to the project timeframe is imperative. DOR/TAX should communicate this expectation to everyone on the project and within the organization. Projects can stall for a number of reasons. Once the Project Management team allows a modification of the timeline, delays become inevitable. Project staff will generally respond and deliver when the leadership informs them there will be no tolerance for delays or missed milestones.

A new system provides an opportunity to adopt new best practice business processes. However, management must be open to new ideas and support the team through the change resistance that may occur. In some cases, those business practices are deeply ingrained in an agency and there can be significant resistance to change. There may even be situations where agencies have sponsored legislation because of legacy system limitations.

2. Staffing Support

It is vital that the project team has the staff it needs to operate. From experience, we have found that personnel involved in the project need to be free from their normal assignments, and that those assignments may need to be backfilled to eliminate the temptation of pulling team members off the project.

Three key factors in meeting adequate project staffing needs:

- Agency information technology staff should fully participate in the implementation
- Agency subject matter experts and users should participate at levels necessary to meet project deliverables and commitments
- Appropriate staff should be available to participate in a train-the-trainer training approach

Perhaps the most long lasting contribution to the success of the project for the organization to make is often the most painful. If you assign someone to the team and it hurts to release them, then you have usually selected the right person. Consider this an investment in your agency's future.

3. Logistic Support

Be prepared to provide accommodations for the project team with the following features:

- Office space - Ideally, the project team will have an office area that is co-located with agency staff. Although a separate workspace is acceptable, we have found that the co-location approach greatly facilitates involving business experts not otherwise assigned to the project in the discussions and decisions related to the new system.

- Worksite access - Project staff will likely require 24x7 access to the project worksite.
- Meeting space - The project team will need frequent access to meeting rooms.
- Workstations - Each project team member will need a workstation and connectivity.
- General office equipment - The project team will need the usual business office accessories.

4. Technology Support

For the most part, technology support will depend on the solution. The project team will need access to make changes to databases and application servers with the proper security to implement the ITMS solution and perform configuration as necessary. Local area network access, email access, and associated hardware support are often peripheral, yet essential, to project success.

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APPENDIX A – Stakeholder Interview Participants

Steven Borrell, Executive Director, Alaska Miners Association, Inc. & Tom Healy, Rock Products Association

Randy Hoffbeck, North Slope Borough

John Boucher, Senior Economist and Jack Kreinheder, Chief Policy Analyst, Office of Management and Budget

Paul Wehe, Transportation Planner I, Alaska Department of Transportation

Susan Bell, Commissioner, Department of Commerce, Community, and Economic Development

Shellene Hutter, Biologist, Alaska Department of Fish and Game

Lisa Call, Severance Tax Senior Specialist, U.S. Financial Reporting & Accounting, Exxon Mobile

Maureen Dolphin, Supervisor, Alaska and Brian Pittman, Conoco-Philips

Paul Syring and Diane Colley, BP Exploration

Dennis Egan, State Senator (and his Aide, Jessie)

Deborah Grundmann, Chief of Staff, State Senator Charlie Huggins

Miles Baker, Chief of Staff, State Senator Bert Stedman

David Teal, Director, and Rob Carpenter, Fiscal Analyst, Legislative Finance Division

Andrew Varner, Executive Director, and Erik O'Brien, Economic Development Specialist, Southwest Alaska Municipal Conference

APPENDIX B – External Stakeholder Interview Questions

Q1: Tell me about your interaction with the Tax Division – which areas of the agency do you typically interact with?

Q2: (Share Tax Division's Mission and Vision). What is your general reaction to the Tax Division's Mission and Vision? Is it appropriate? Does it look like they're focusing on the right things? Is anything missing?

Q3: Based on your interactions with the Tax Division, are there a few words that aptly describe their general reputation?

Q4: In your opinion, is there anything the Division should be doing to improve tax administration? Are there areas that should receive increased attention and focus?

Q5: Are there additional services you would like to see the Tax Division provide to taxpayers?

Q6: Are there valuable services the Tax Division currently provides that you want to make sure they continue providing in the future?

Q 7: Is there any other feedback you would like me to share with the Tax Division?

APPENDIX C – Mission and Vision External Feedback

TAX desired contributions from external stakeholders to serve as an input for this study, and to provide validation prior to an annual review of its vision and mission statements. FAST interviewed 20 stakeholders including taxpayers, association representatives, legislators and legislative staff, state agency personnel, and a local government representative. After sharing a copy of the previous mission and vision statements, the questions posed to stakeholders were:

- What is your general reaction to TAX's mission and vision?
- Is it appropriate?
- Does it look like they're focusing on the right things?
- Is anything missing?

General Reaction and Comments

Feedback ranged from the vision and mission "look straightforward and complete" to several comments noting that the statements are "quite a blend of things" and that TAX could "tighten up their focus with fewer statements." One stakeholder observed, "A focus on fairness, efficiency, and effectiveness would seem about right." Another stakeholder put it this way:

"They're not focused on the wrong things, but where do they place their emphasis? If they're focused on too many different things, they can't effectively focus on their central purpose which is collecting taxes to fund government services."

Mission: Collect taxes, inform stakeholders, regulate charitable gaming

Several stakeholders noted that collecting all the revenues due the state is TAX's primary purpose and is properly prominent in the mission statement.

A few interviewees had questions about the phrase "inform stakeholders." Several seemed unsure exactly what the phrase intended to communicate, "Inform them about what?" Who do they mean when they say "stakeholders?" One noted, "*Inform stakeholders* seems a little weak – it's more important to cooperate and partner than to inform." Another observed, "Being a resource to other agencies in the executive branch and to the legislature is important – it might be nice to go beyond *inform*." Another added, "They don't say anything about playing well with others in state government and getting along well with the legislature."

Increase revenue collections and compliance

The most frequent comment throughout all the interviews was directed to the statement "increase revenue collections."

One stakeholder explained,

"I'm not sure what the Tax Division means when they say they're trying to increase revenue collections. Shouldn't they just be trying to collect the correct amount that is due? Increasing compliance makes sense, but simply *increasing revenue collection* sounds like they're just out for money – even if taxpayers are already paying what they owe."

Another observed, "Trying to move the compliance needle closer to 100% is important. Collecting all the revenues that are due and doing it efficiently and effectively is important, too. But simply *increasing revenue* seems to communicate the wrong message." Another interviewee mentioned that accuracy is important in saying, "Collecting the right amount – no more and no less – should be part of their focus."

Others added that TAX should emphasize the concepts of simplicity and clarity:

"It's not just about collecting money from taxpayers – the agency's focus should be making it as easy as possible to pay what you owe. It's like going to the dentist – you want the experience to be as painless as possible."

And:

"Clarity of tax application is also important. As a taxpayer, it's hard to know what to report and providing clear instructions is part of the job."

The public has confidence in the division's integrity, efficiency, and fairness

Several stakeholders noted the importance of operating efficiently. Stakeholders specifically reminded us of the need to report the same information many times and in many different ways to satisfy TAX's various systems. One stakeholder said, "It's good they want to focus on efficiency because the Tax Division's inefficiency makes taxpayer interaction with the division inefficient."

Customers receive excellent service

Many persons interviewed commented on the importance of good customer service. One clarified,

"It's not just about friendly service. If you have to call up five times to get the information you need, it's nice to talk to a friendly voice five times. But efficient and competent service is important, too. They should be able to provide the information you need quickly and easily."

The division maximizes the use of technology in its business processes; the division has online filing for each program it administers

Most stakeholders commented on the two vision statements addressing technology. There was concern that the statement implied using the latest technology just because it is new. "The important thing is to use technology wisely and effectively." The most frequent comment questioned the idea of *maximizing* the use of technology. One stakeholder explained:

"It's not about arbitrarily using technology to the max – you use technology to improve customer service or increase the public's confidence in the Tax Division. Technology is a means to achieve the division's goals."

Another person also highlighted this area and reiterated:

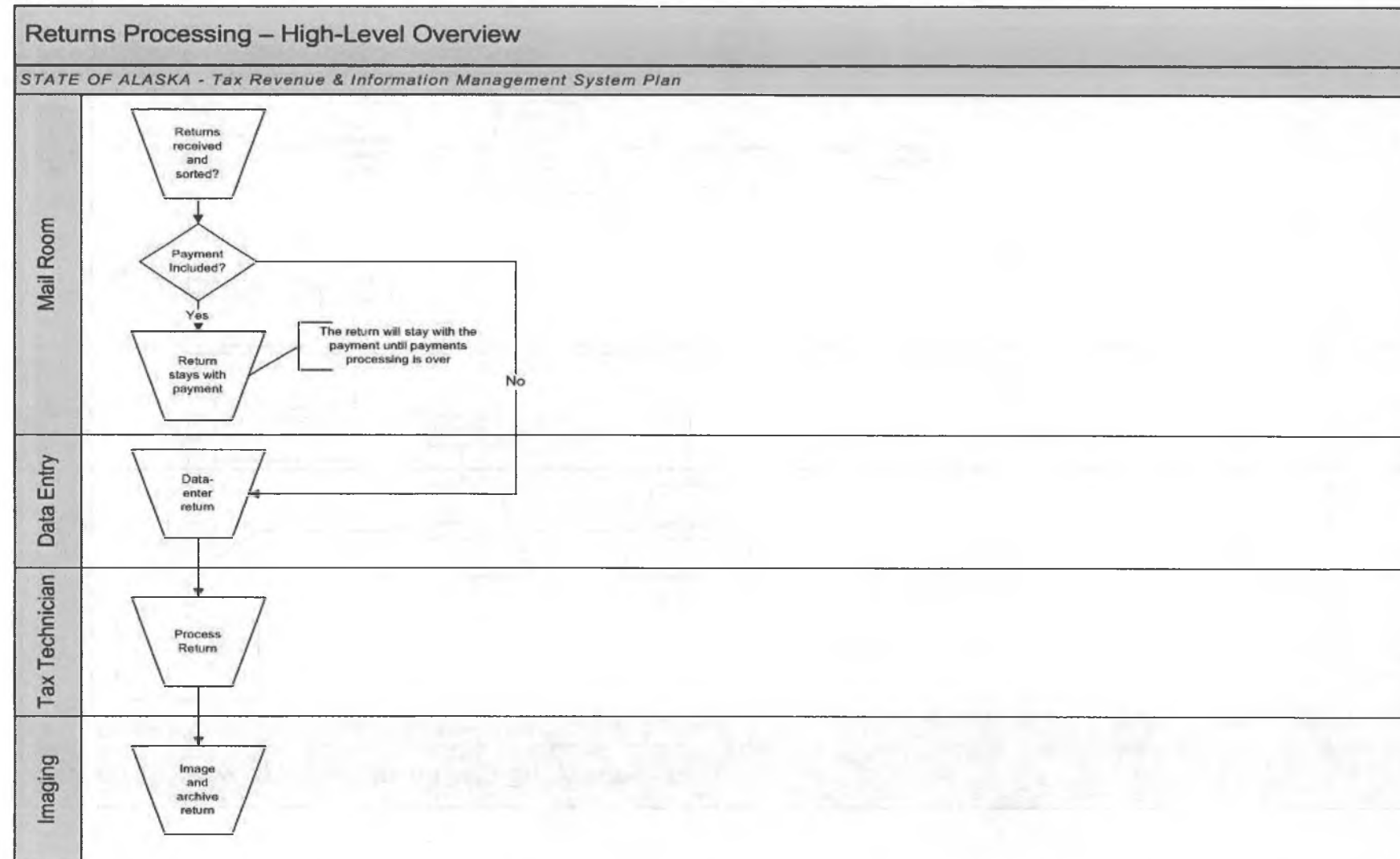
"We don't want the Tax Division chasing all the latest technology just so they can have the new stuff. What's important to taxpayers is a stable platform, not something that is changing all the time."

Several thought the two technology statements were redundant and noted they both connected to efficiency. Several taxpayers also stated that they hoped TAX understood that online filing is more than just the ability to fill out a form on the Internet. Specifically, one person put it very simply:

"The Tax Division needs a better platform to ease electronic reporting. What's needed is electronic data interchange."

APPENDIX E – High-Level Diagrams

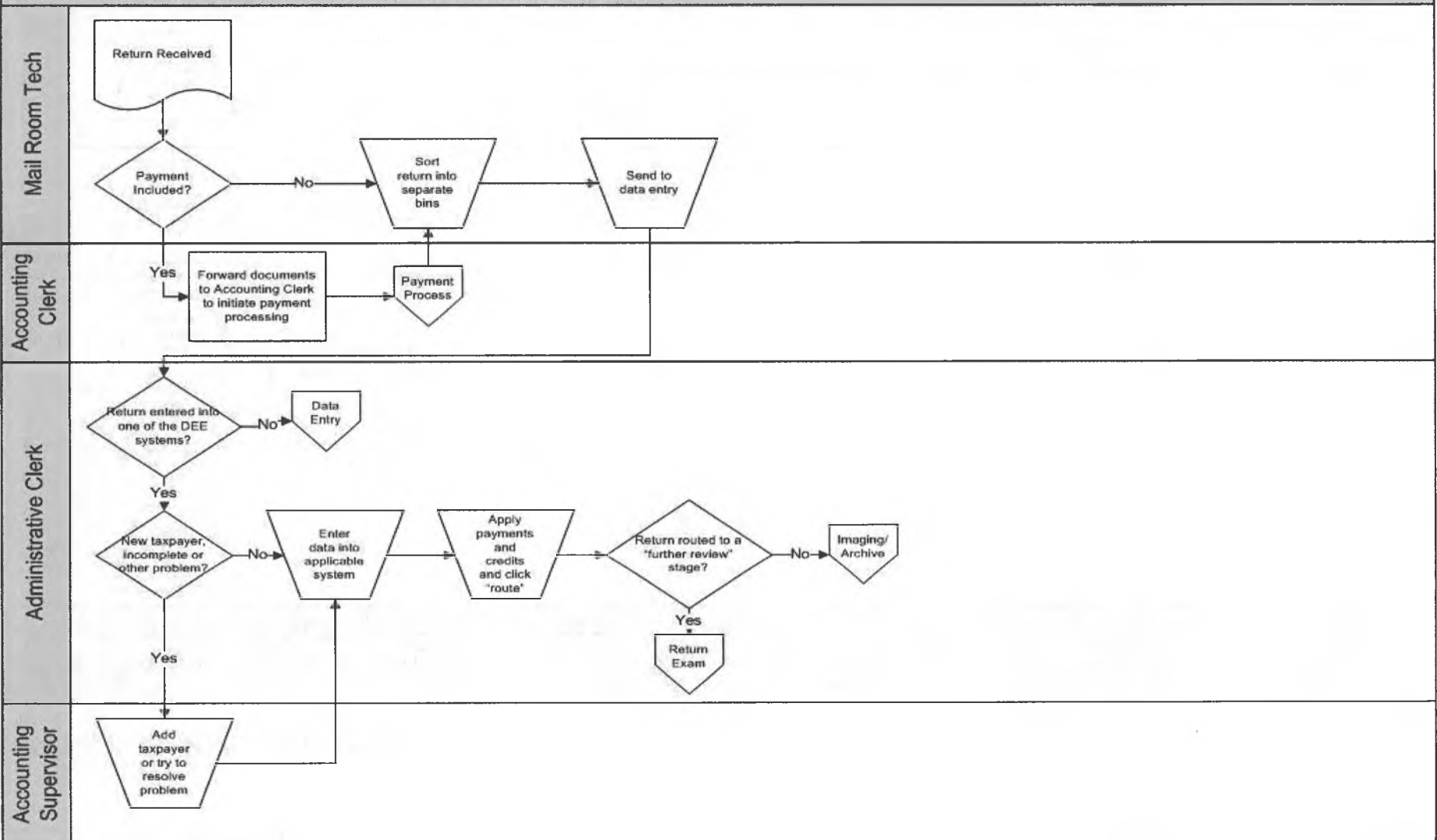
E. 1



E. 2

Returns Processing – Mail Room/Data Entry, Juneau

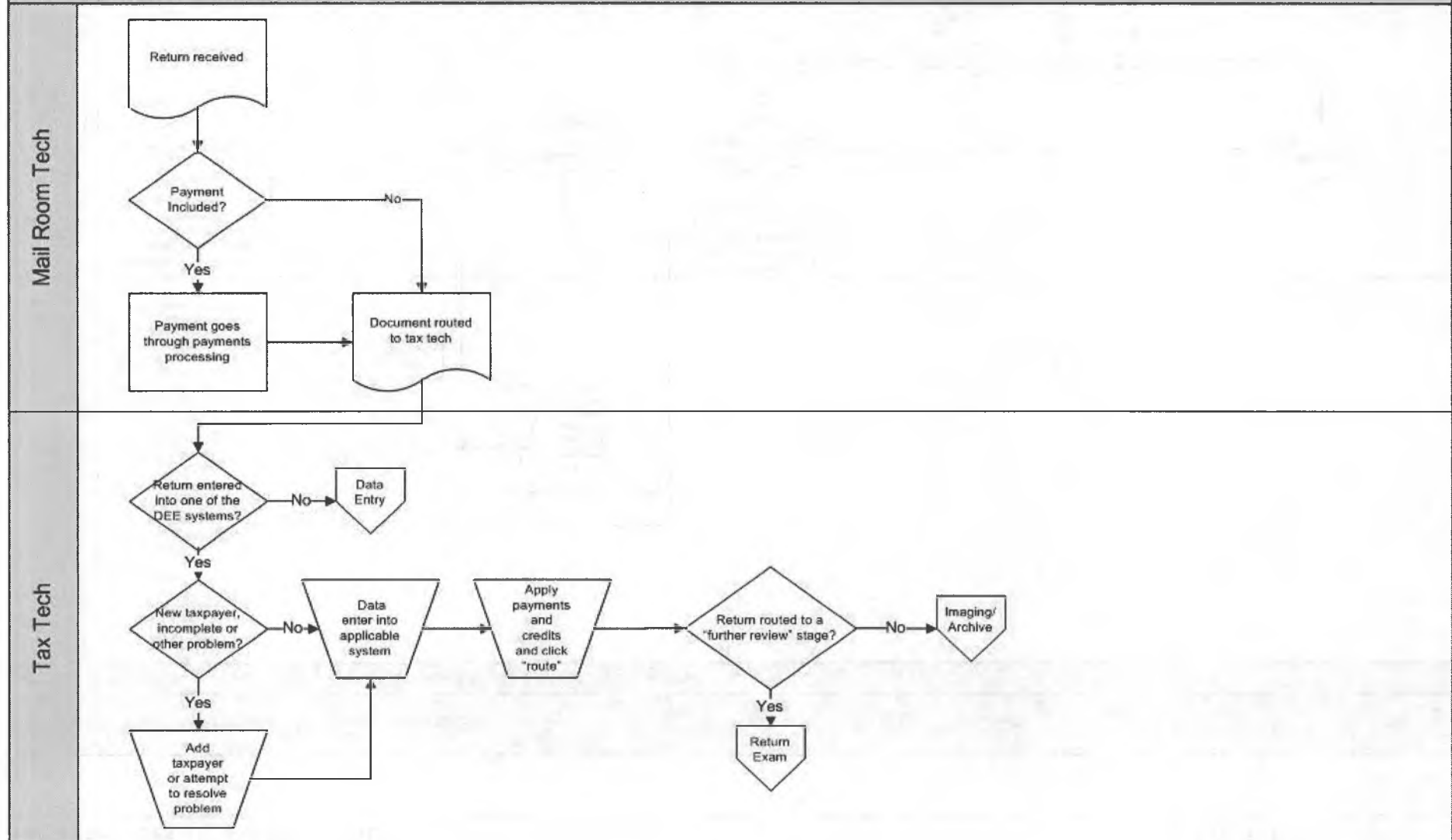
STATE OF ALASKA - Tax Revenue & Information Management System Plan



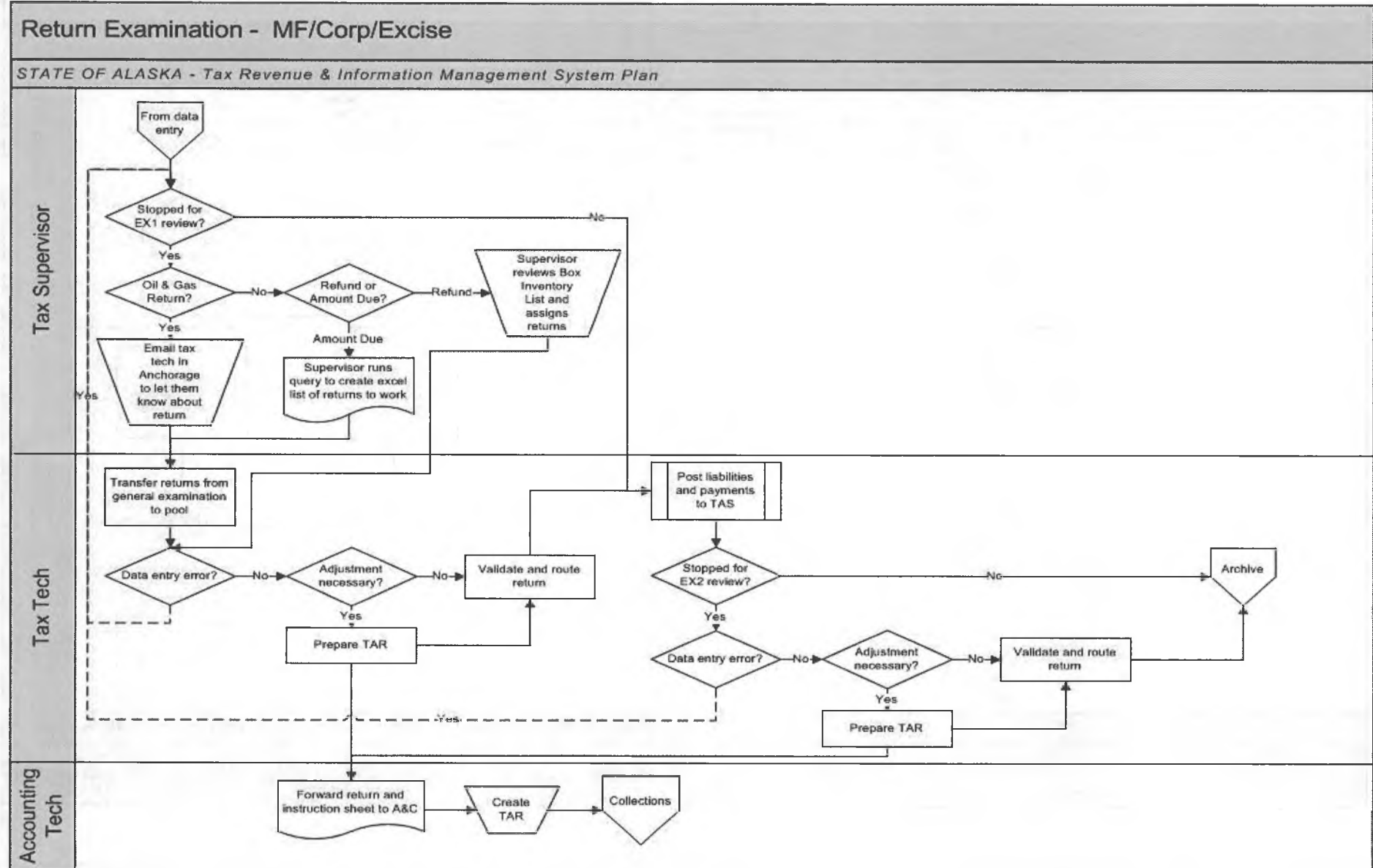
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Returns Processing – Mail Room/Data Entry, Anchorage

STATE OF ALASKA - Tax Revenue & Information Management System Plan



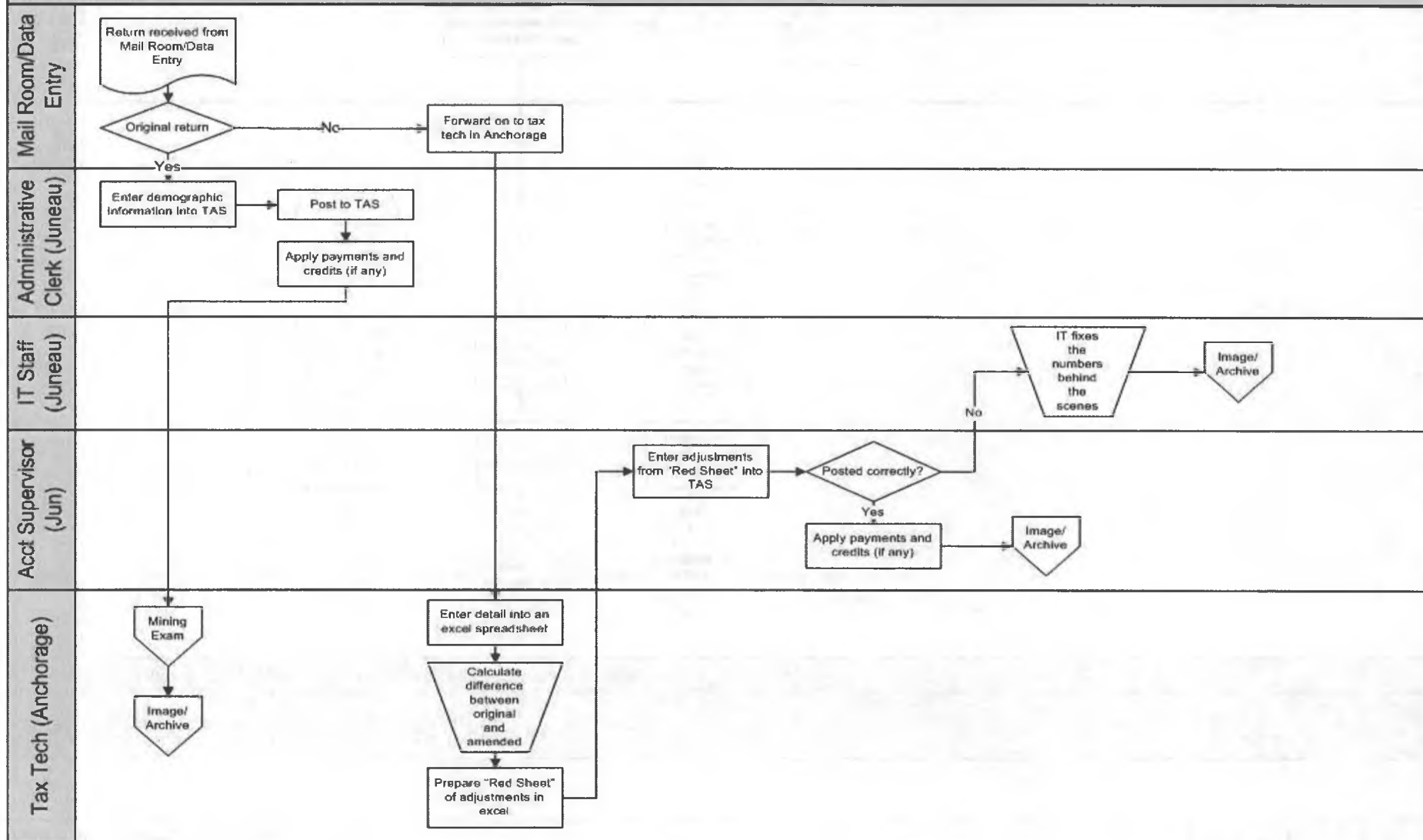
E. 4



E. 5

Returns Processing - Mining License

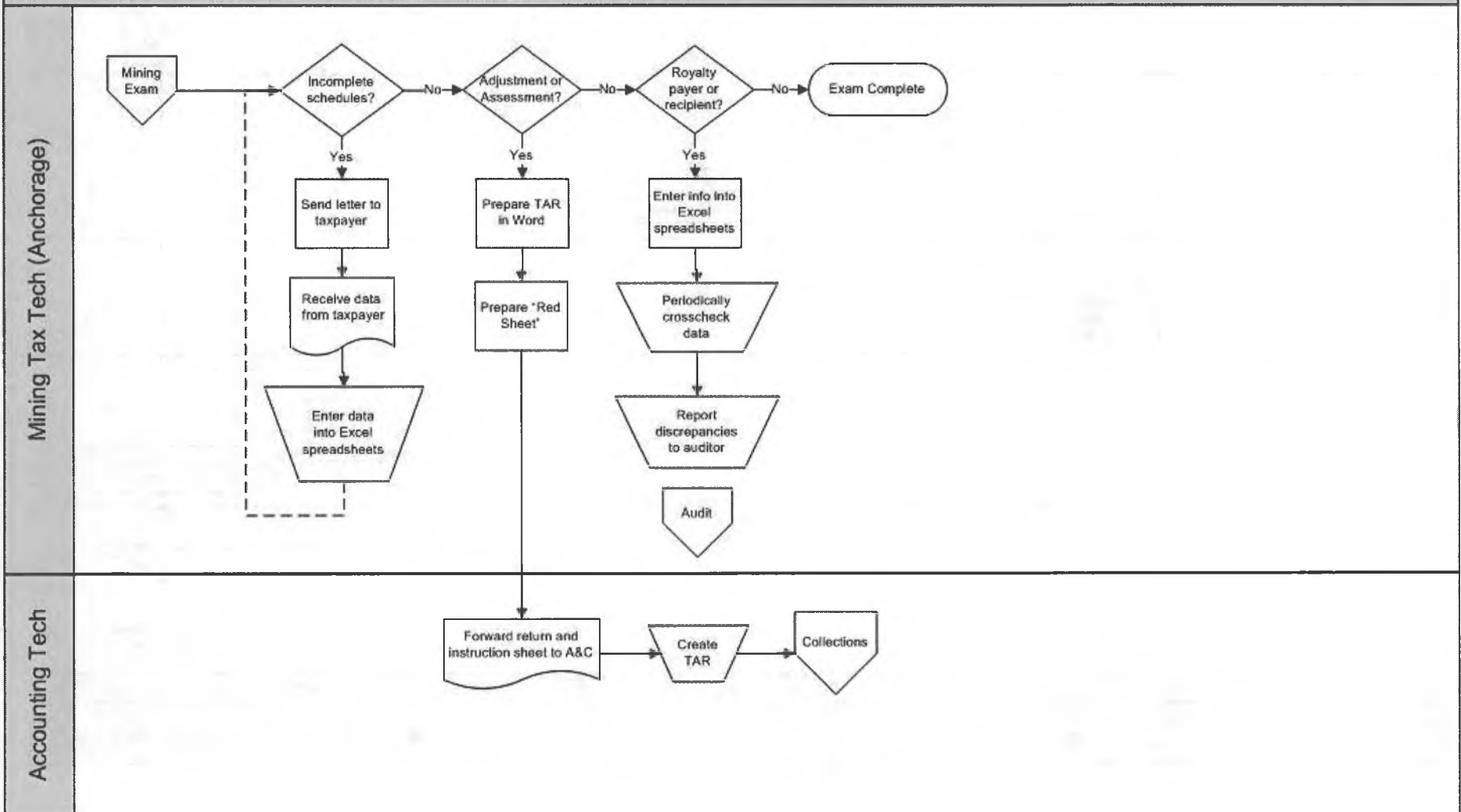
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 6

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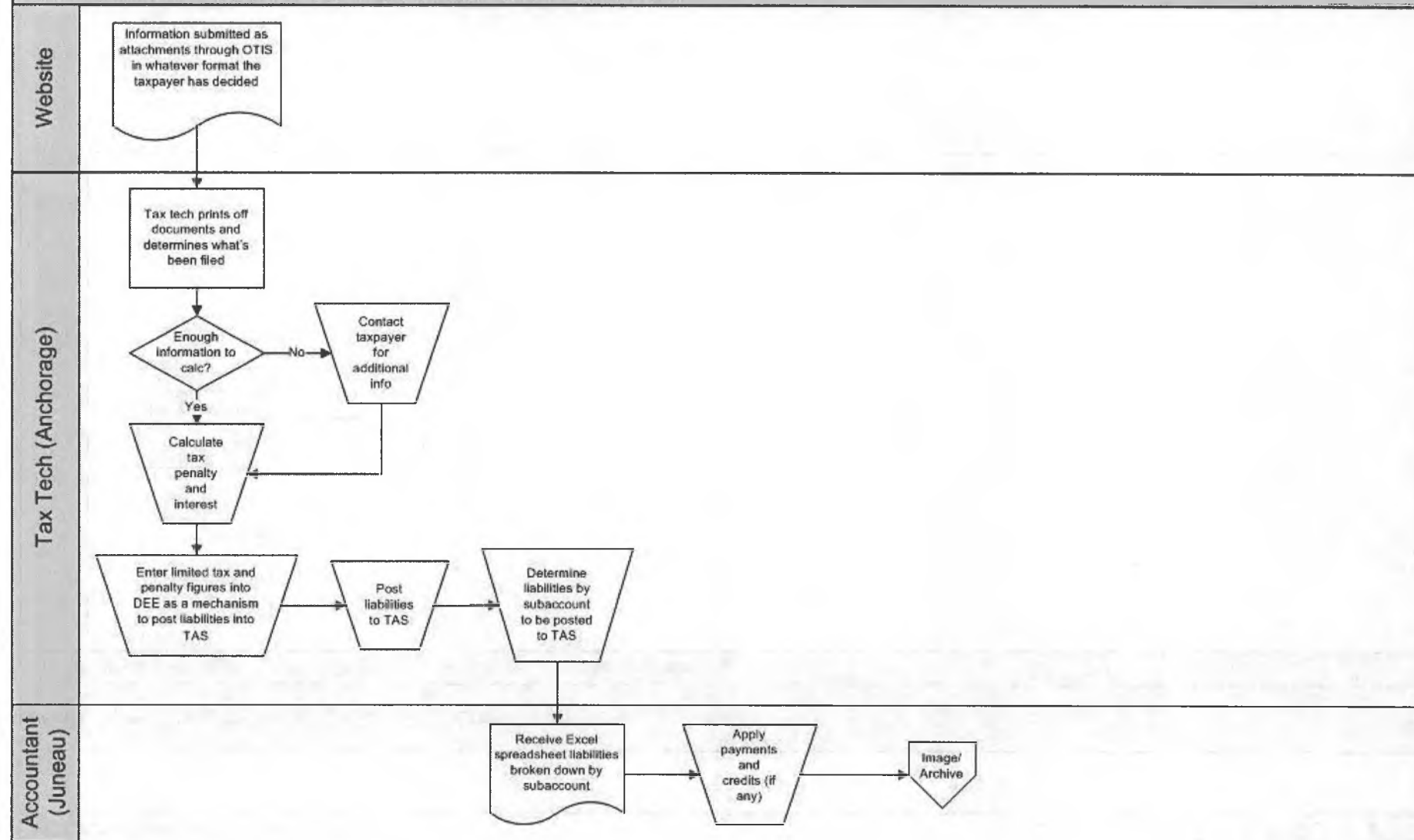
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 7

Returns Processing - Oil & Gas Production

STATE OF ALASKA - Tax Revenue & Information Management System Plan

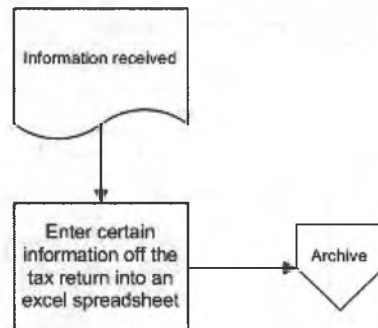


E. 8

Returns Processing - Oil & Gas Property

STATE OF ALASKA - Tax Revenue & Information Management System Plan

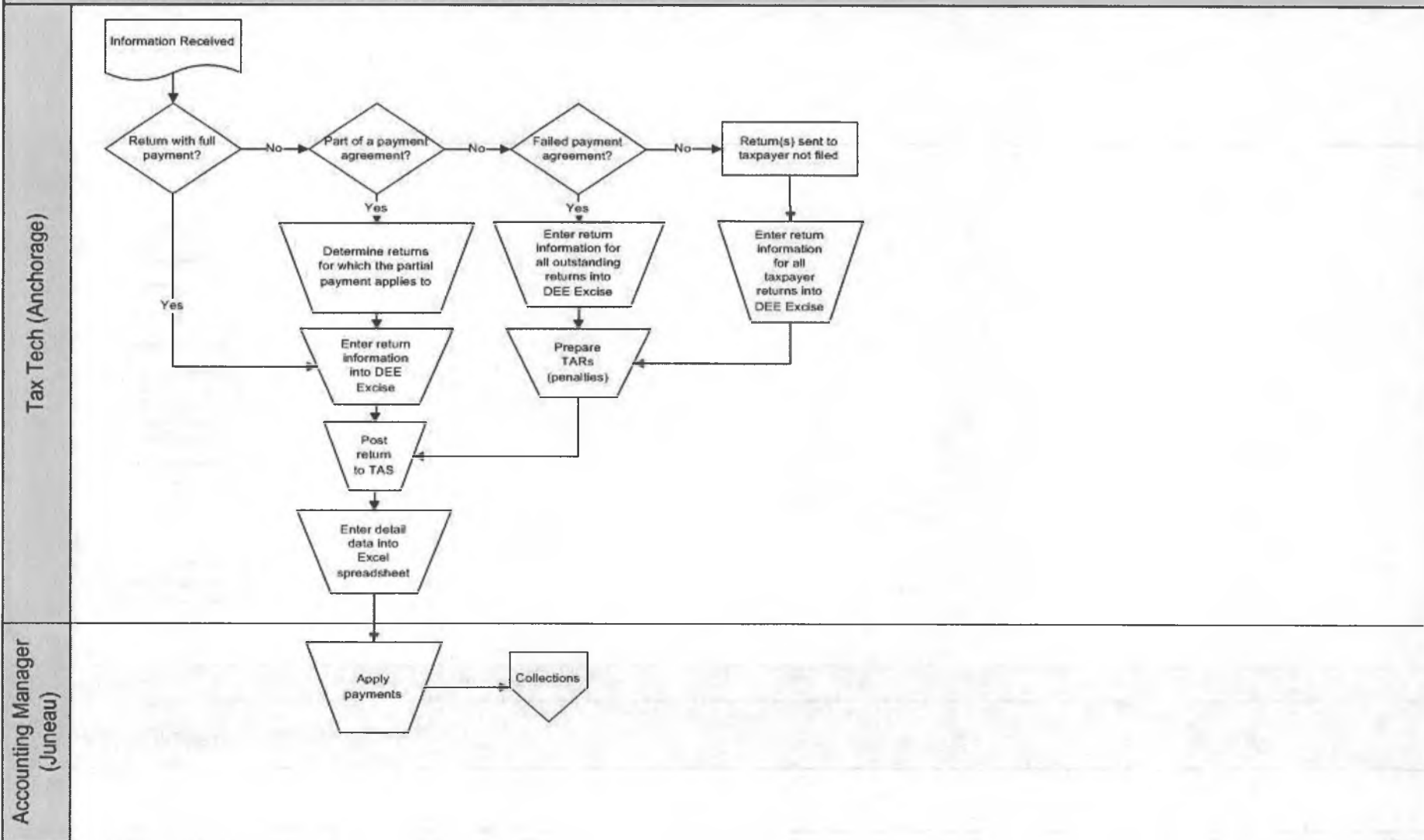
Tax Technician (Anchorage)



E. 9

Return Processing - Personal Cigarette

STATE OF ALASKA - Tax Revenue & Information Management System Plan

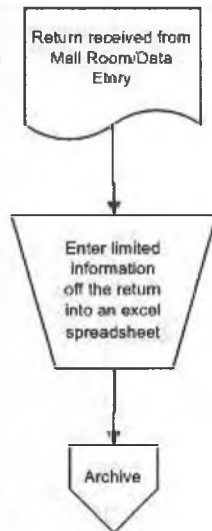


E. 10

Returns Processing - Partnership

STATE OF ALASKA - Tax Revenue & Information Management System Plan

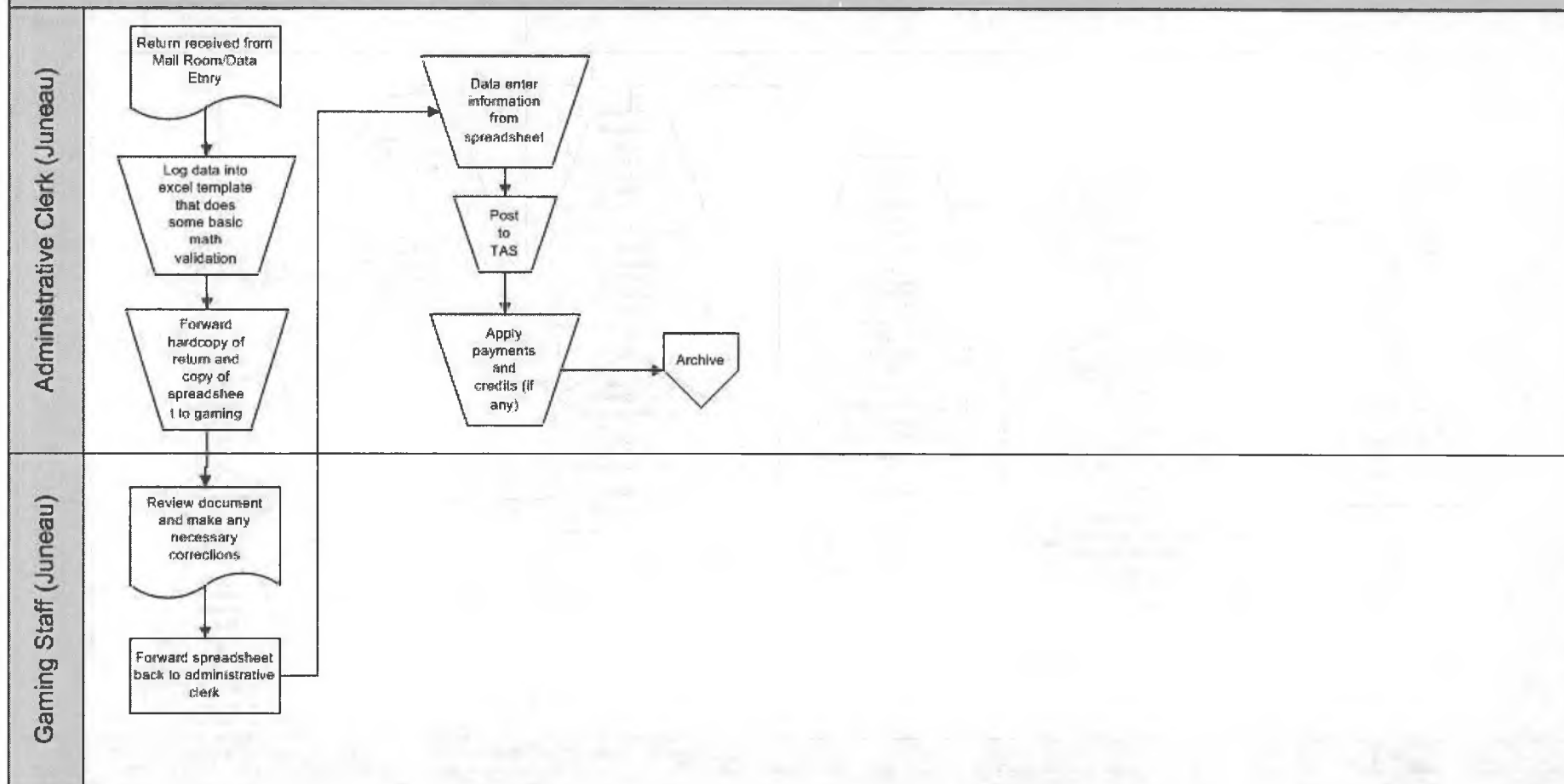
Administrative Clerk (Juneau)



E. 11

Returns Processing - Gaming

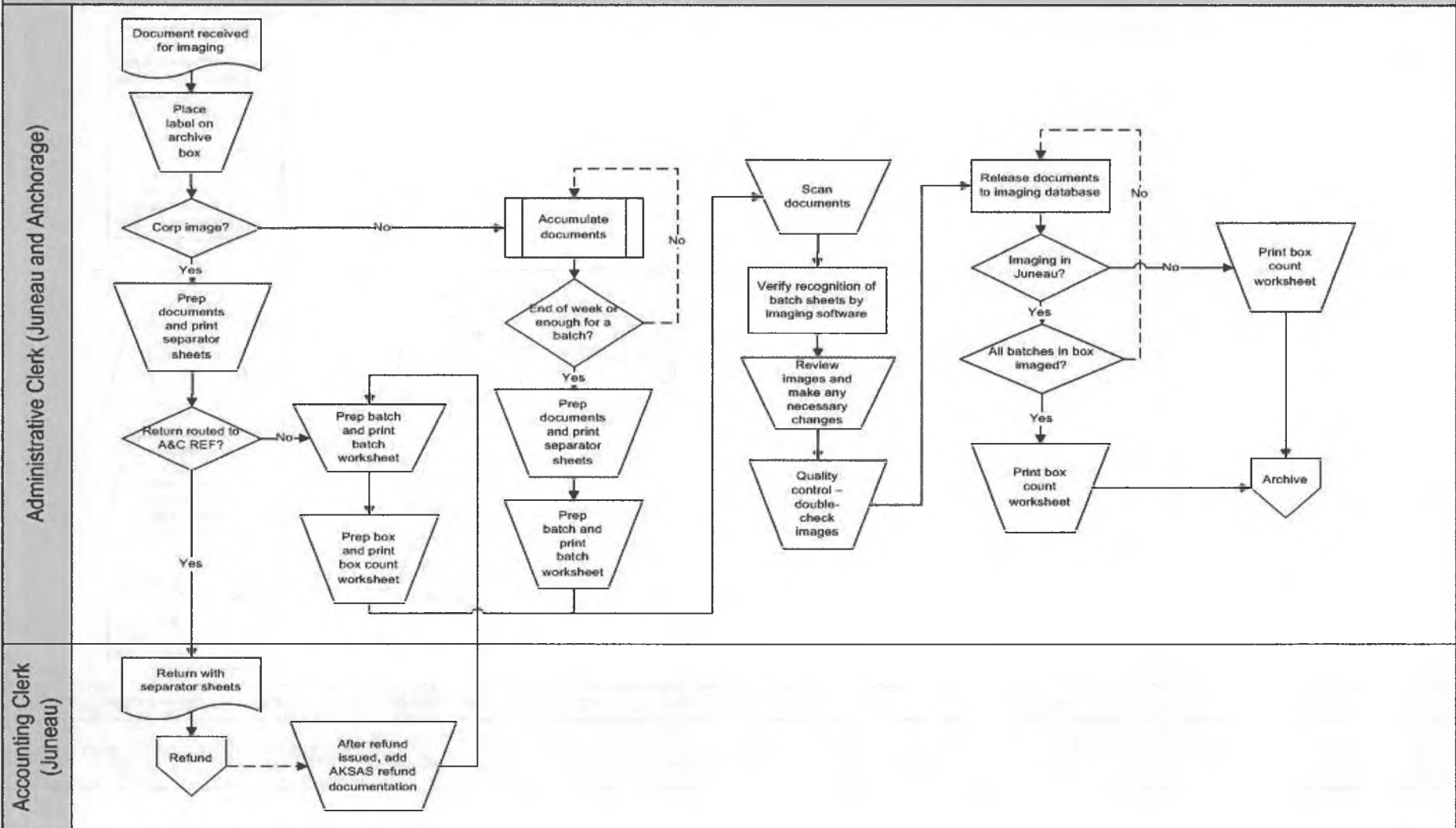
STATE OF ALASKA – Tax Revenue & Information Management System Plan



E. 12

Imaging

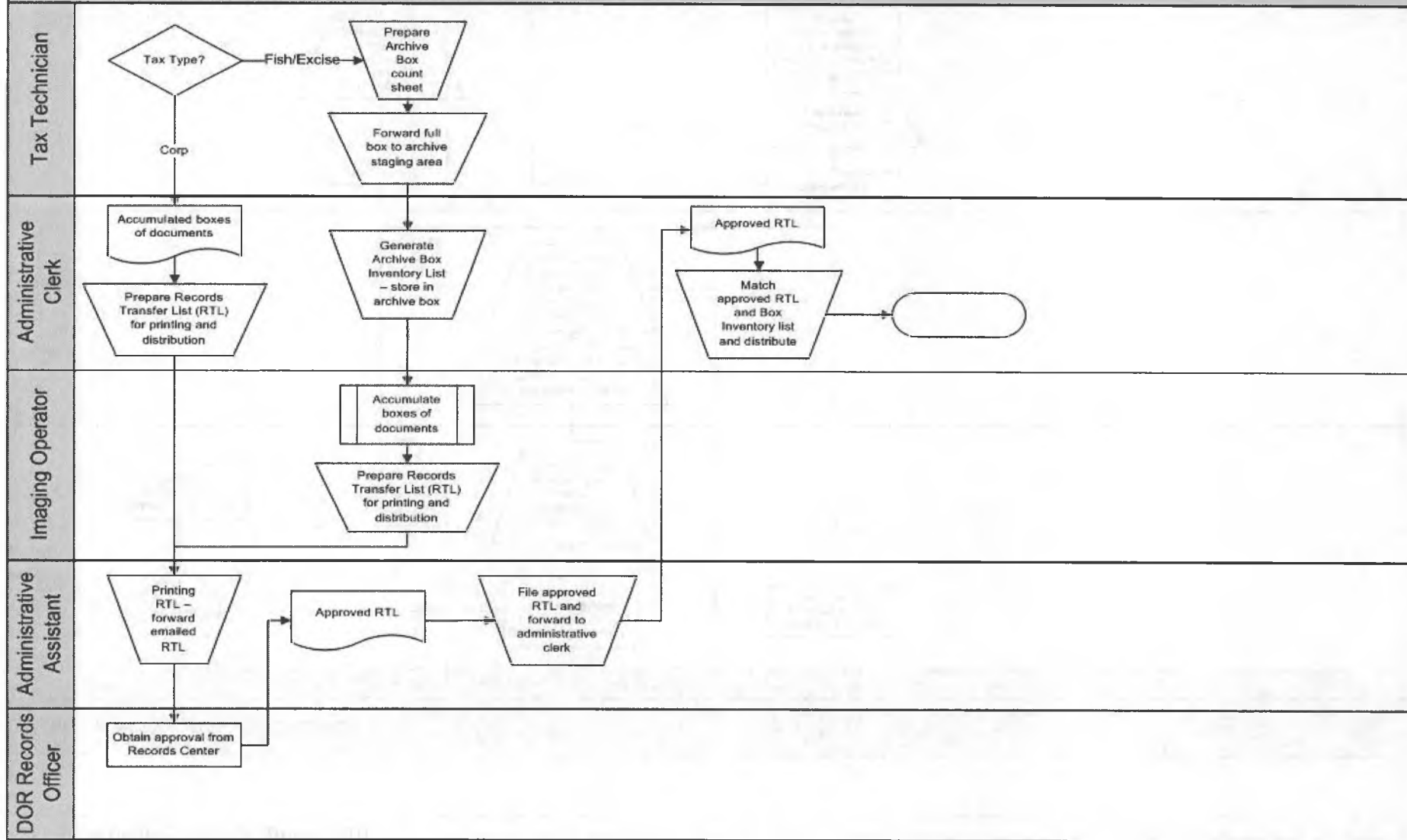
STATE OF ALASKA - Tax Revenue & Information Management System Plan



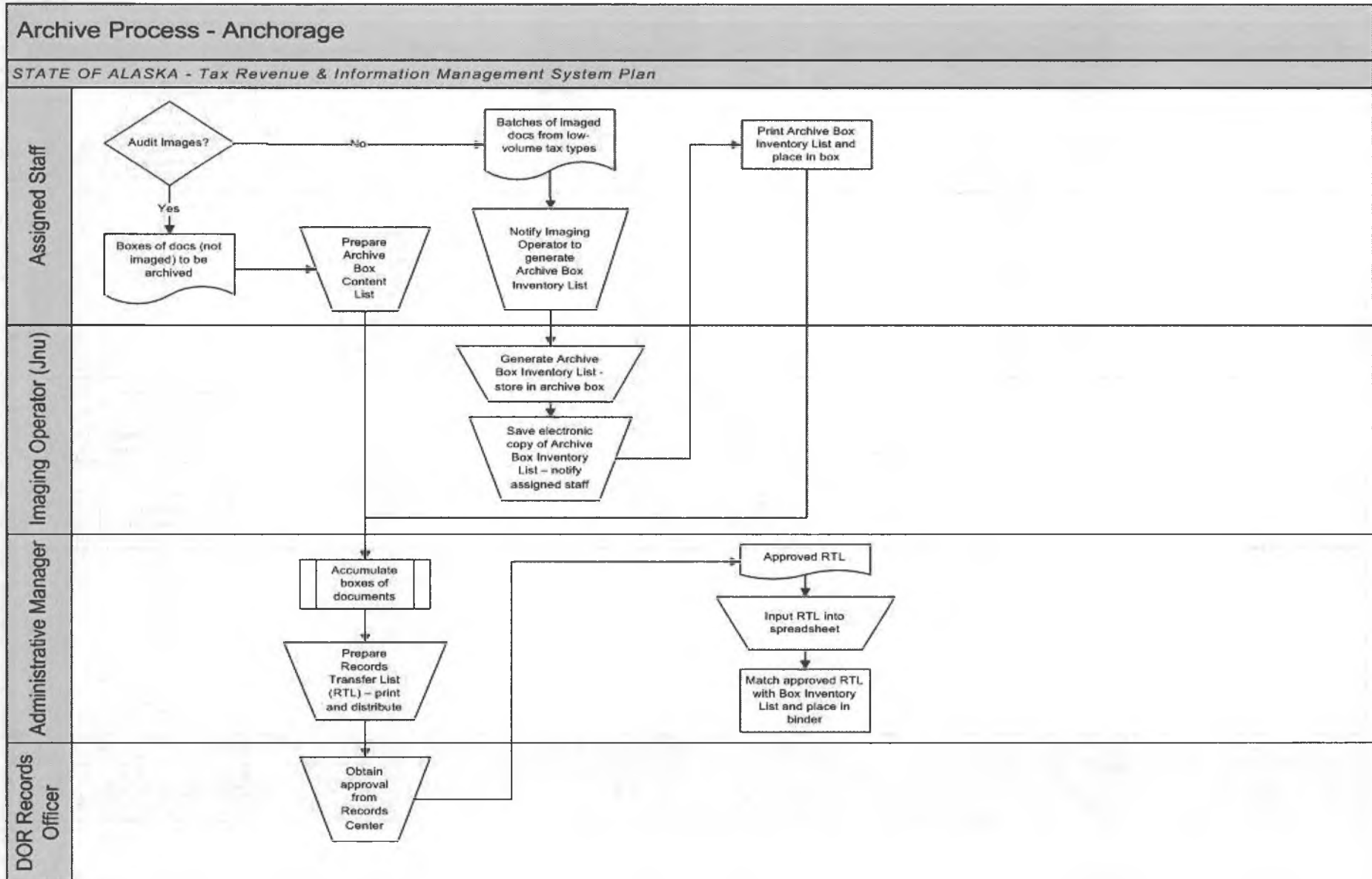
E. 13

Archive Process - Juneau

STATE OF ALASKA - Tax Revenue & Information Management System Plan



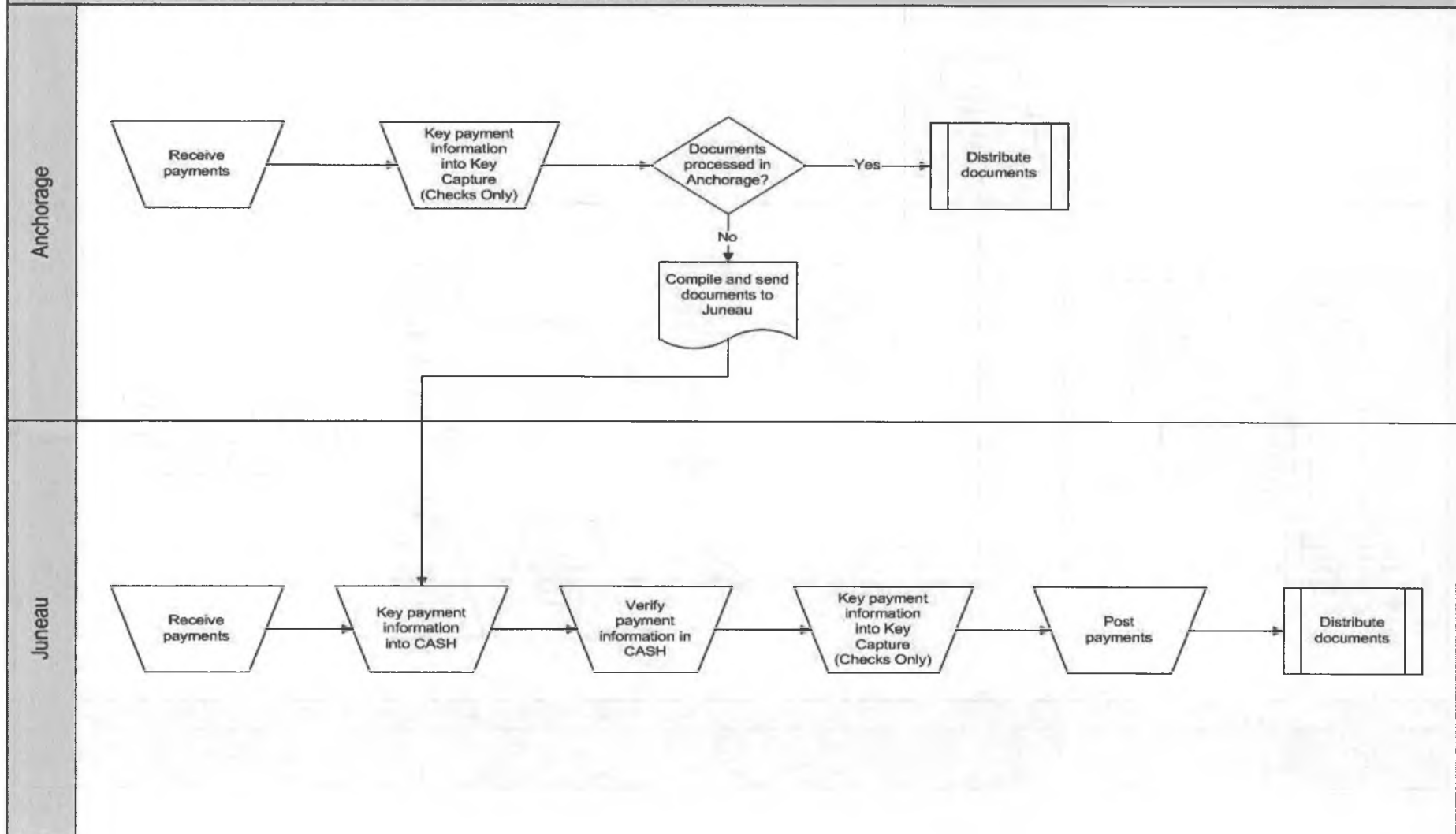
E. 14



E. 15

Payments Overview

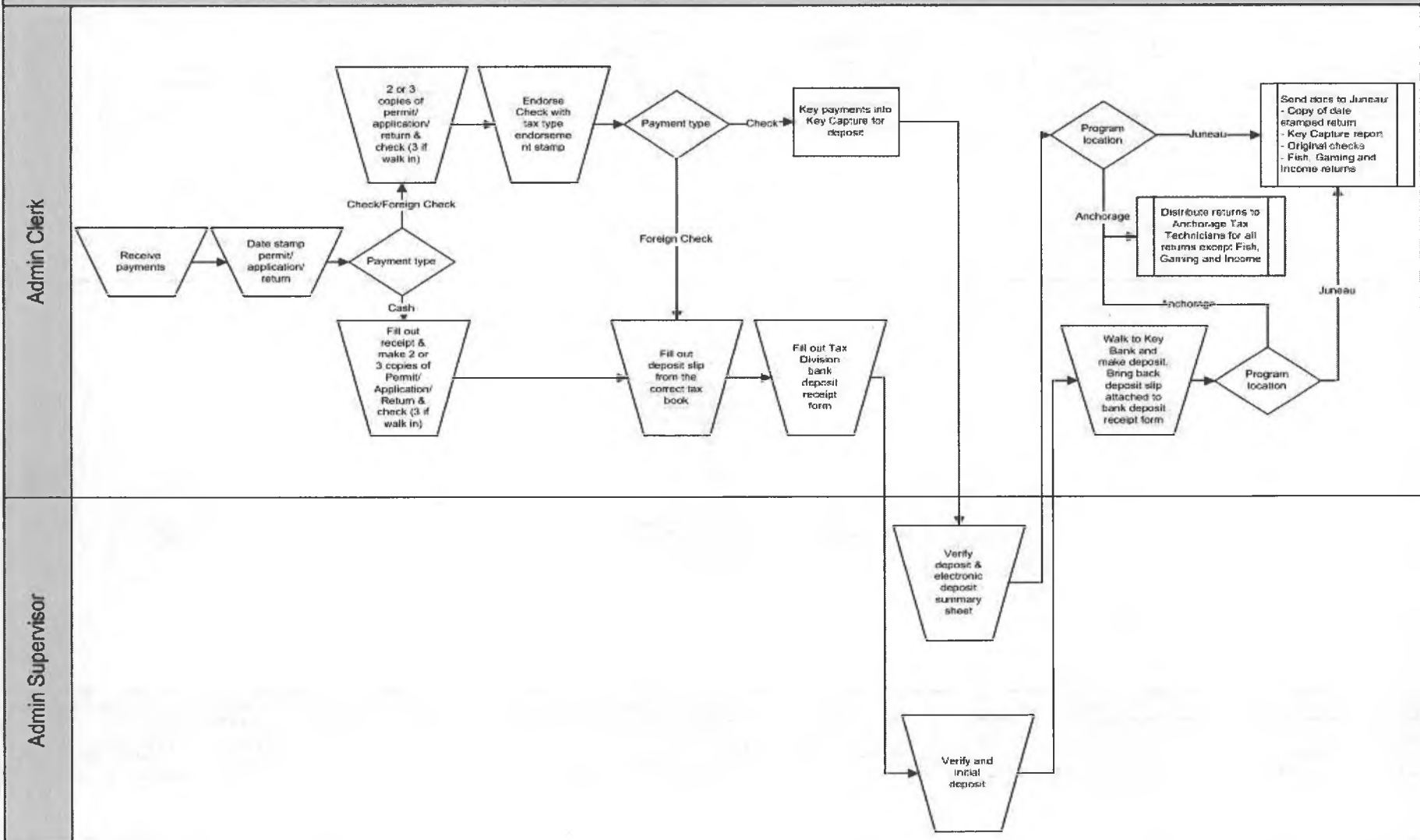
STATE OF ALASKA - Tax Revenue & Information Management System Plan



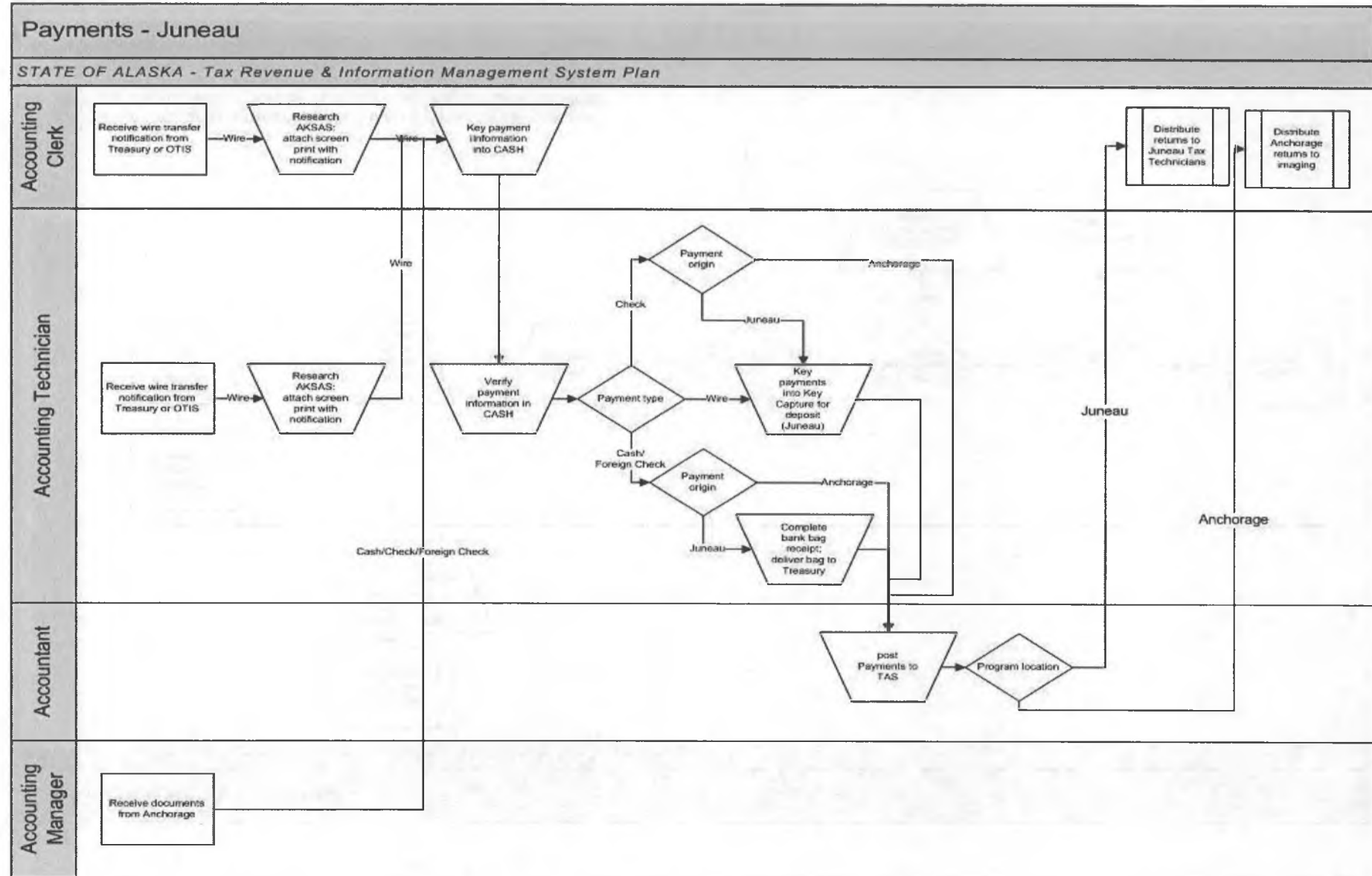
E. 16

Payments – Anchorage

STATE OF ALASKA - Tax Revenue & Information Management System Plan



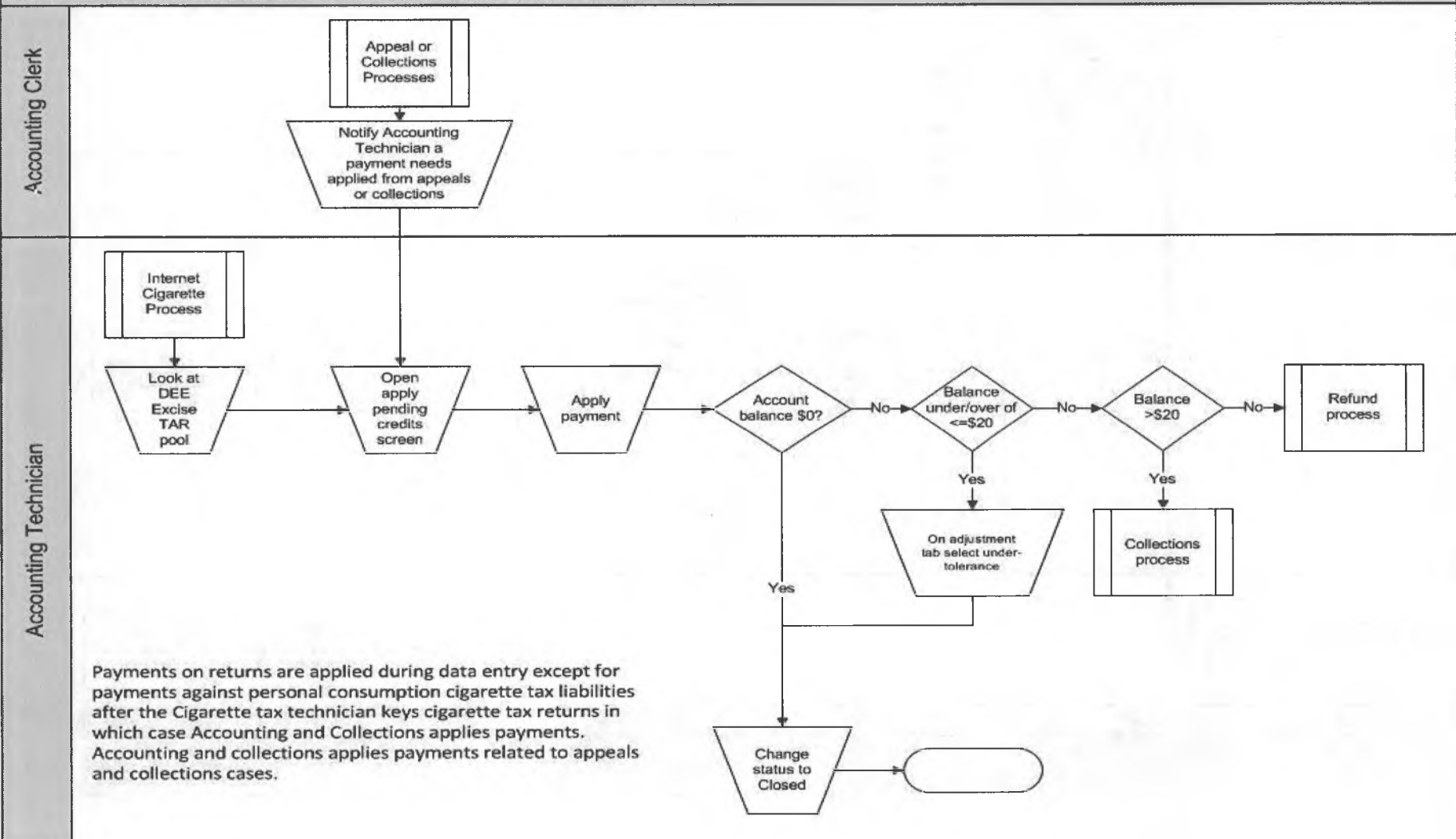
E. 17



E. 18

Payments – Apply Payment

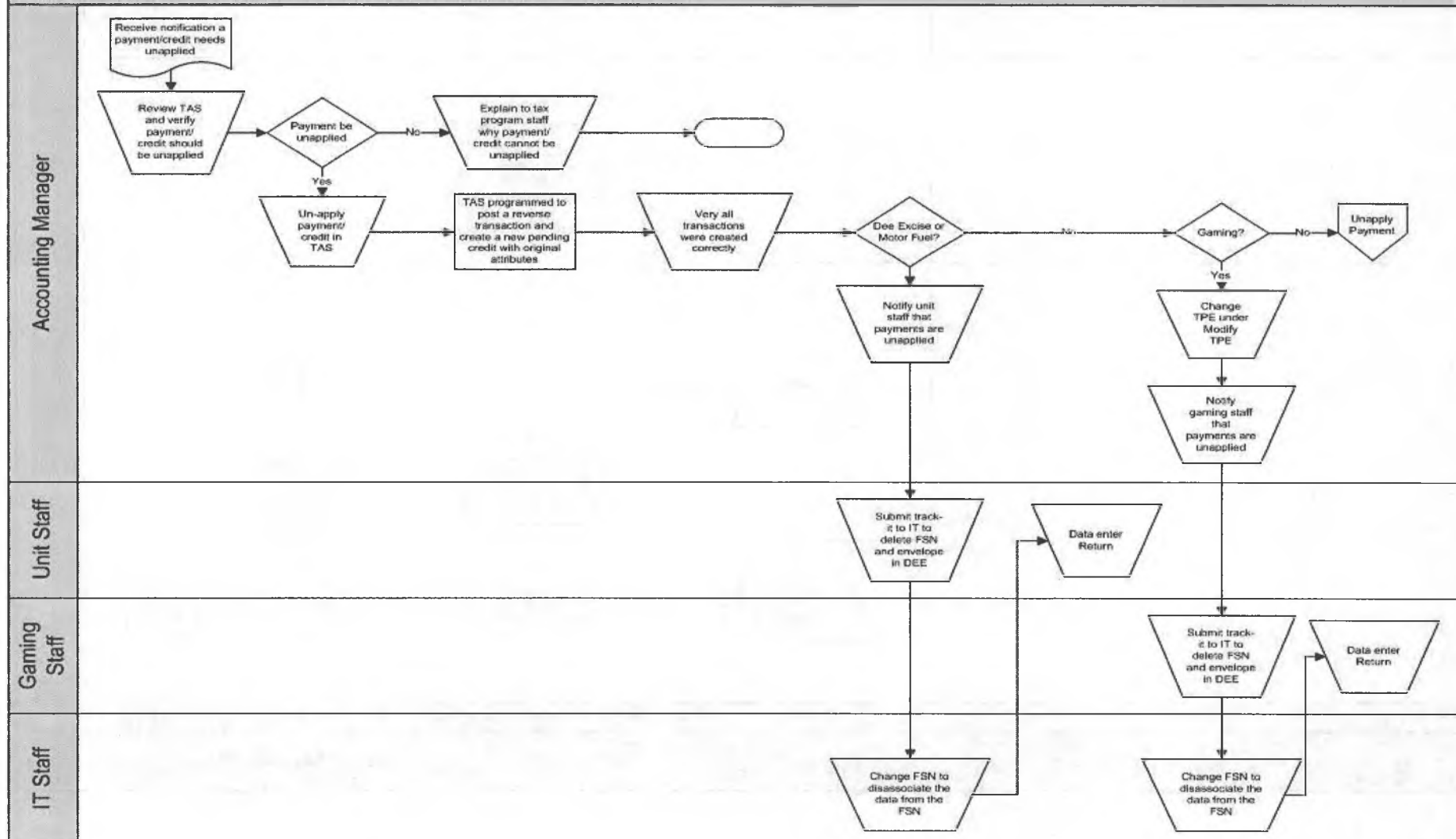
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 19

Payments – Unapply Payment

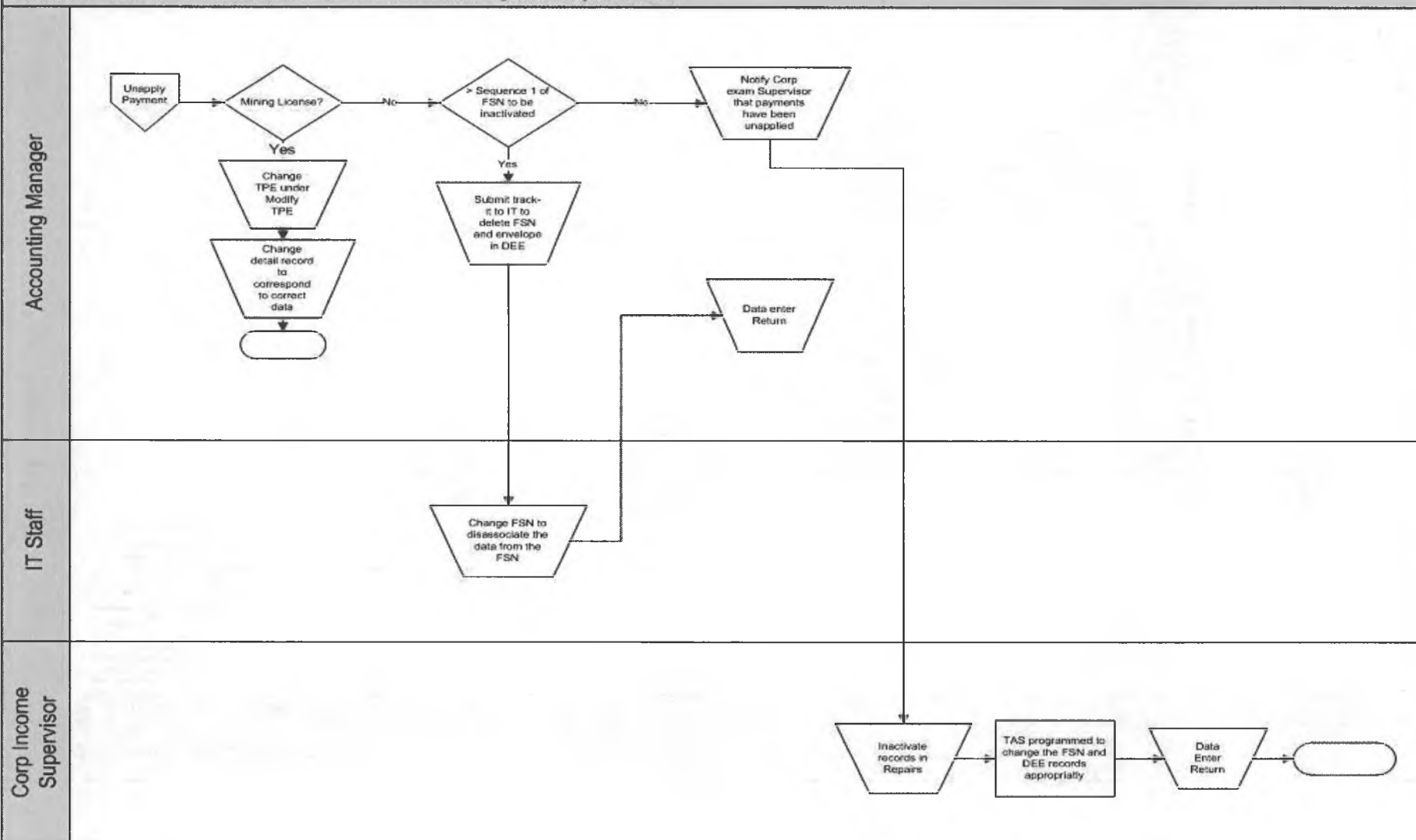
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 20

Payments – Unapply Payment

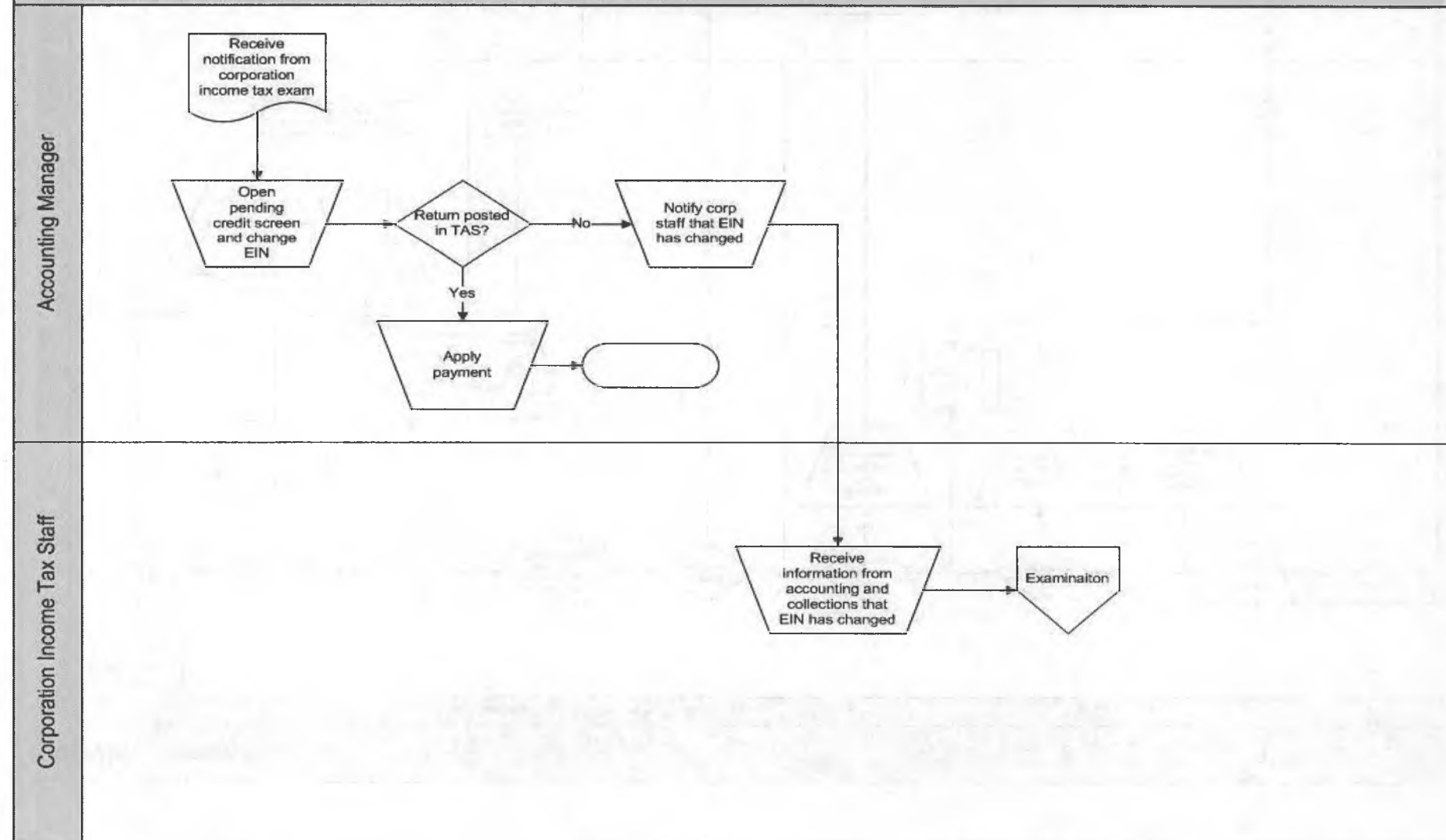
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 21

Payments – Fix PC EIN

STATE OF ALASKA - Tax Revenue & Information Management System Plan



Refunds - Preparation

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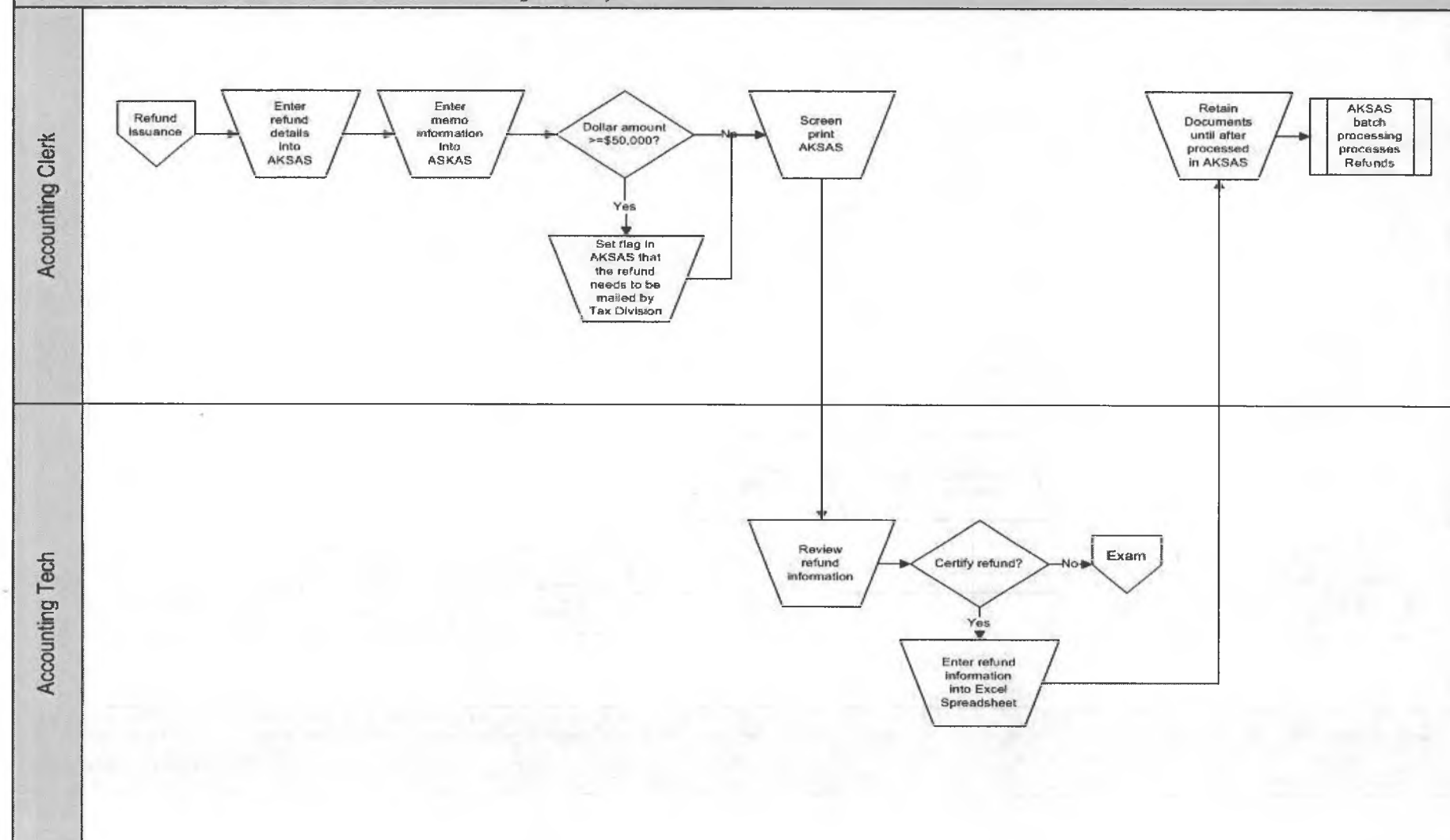
graph TD
    Start([Receive refund requests]) --> Normal{Normal refund?}
    Normal -- Yes --> ReviewTAS[Review TAS for other debt]
    Normal -- No --> Pending{Pending credit refund?}
    Pending -- No --> Gaming{Gaming refund?}
    Pending -- Yes --> ScreenCredits[/Screen print pending credits/]
    Gaming -- No --> ReviewDoc[/Review refund documentation and check TAS amounts/]
    Gaming -- Yes --> ApproveMemo[/Approve memo and keep a copy/]
    ReviewDoc --> OffsetReq{Offset required?}
    ApproveMemo --> SendMemo[/Send memo to DOR Finance/]
    SendMemo --> AfterIssuance[/After refund issuance/]
    OffsetReq -- No --> NeedSupervisor{Need supervisor approval?}
    OffsetReq -- Yes --> OffsetDebt[/Offset Debt/]
    NeedSupervisor -- No --> InterestNeed{Interest need to be paid?}
    NeedSupervisor -- Yes --> SendSupervisor[/Send to Tax Program Supervisor for approval/]
    InterestNeed -- No --> CodeOffsetsTAS[/Code offsets in TAS/]
    InterestNeed -- Yes --> CalculatePost[/Calculate and post interest/]
    CalculatePost --> ScreenPrint[/Screen print and highlight interest information/]
    CodeOffsetsTAS --> RouteFileroom[/Route to filercom in DEE/]
    ScreenPrint --> ScreenPrint
    SendSupervisor --> ReceiveApproval[Receive approval]
    ReceiveApproval --> ReviewRefund[Review refund for approval]
    ReviewRefund --> ApproveRefund{Approve refund?}
    ApproveRefund -- No --> Exam{{Exam}}
    ApproveRefund -- Yes --> RefundIssuance[/Refund issuance/]
    ScreenCredits --> OtherDebt{Other debt?}
    OtherDebt -- No --> CodeOffsetsTAS
    OtherDebt -- Yes --> ForwardSupervisor[/Forward to Corp Supervisor to determine offsets/]
    ForwardSupervisor --> CodeOffsetsTAS
    CodeOffsetsTAS --> RefundIssuance
    RefundIssuance --> RefundIssuance
    
```

The flowchart details the refund process, starting with 'Receive refund requests'. It branches into 'Normal refund?' and 'Pending credit refund?'. 'Normal refund?' leads to 'Review TAS for other debt' and then to 'Offset required?'. 'Pending credit refund?' leads to 'Screen print pending credits' and then to 'Other debt?'. 'Gaming refund?' leads to 'Approve memo and keep a copy' and then to 'Send memo to DOR Finance'. 'Offset required?' leads to 'Offset Debt' if 'Yes' and to 'Need supervisor approval?' if 'No'. 'Need supervisor approval?' leads to 'Send to Tax Program Supervisor for approval' if 'Yes' and to 'Interest need to be paid?' if 'No'. 'Interest need to be paid?' leads to 'Calculate and post interest' and then to 'Screen print and highlight interest information' if 'Yes', and to 'Code offsets in TAS' if 'No'. 'Send to Tax Program Supervisor for approval' leads to 'Receive approval', which then leads to 'Review refund for approval'. 'Review refund for approval' leads to 'Approve refund?'. 'Approve refund?' leads to 'Exam' if 'No' and to 'Refund issuance' if 'Yes'. 'Screen print pending credits' leads to 'Other debt?'. 'Other debt?' leads to 'Forward to Corp Supervisor to determine offsets' if 'Yes' and to 'Code offsets in TAS' if 'No'. 'Forward to Corp Supervisor to determine offsets' leads to 'Code offsets in TAS'. 'Code offsets in TAS' leads to 'Refund issuance'. 'Refund issuance' leads to 'Refund issuance'.

E. 23

Refund - Issuance

STATE OF ALASKA - Tax Revenue & Information Management System Plan

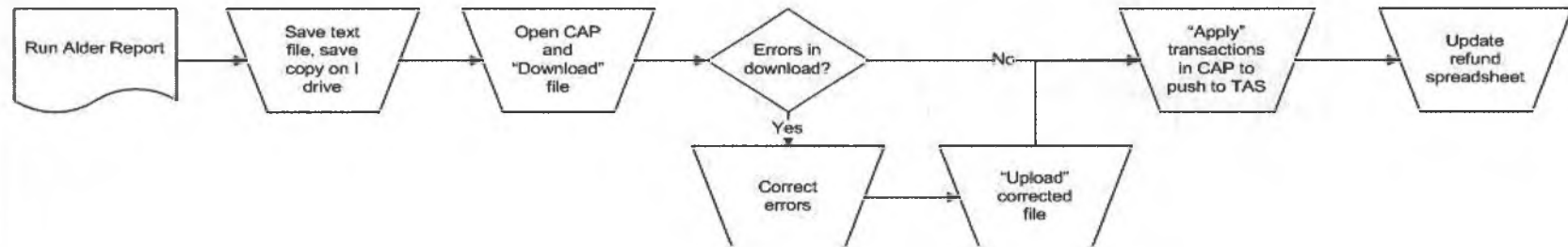


E. 24

Refund - Download

STATE OF ALASKA - Tax Revenue & Information Management System Plan

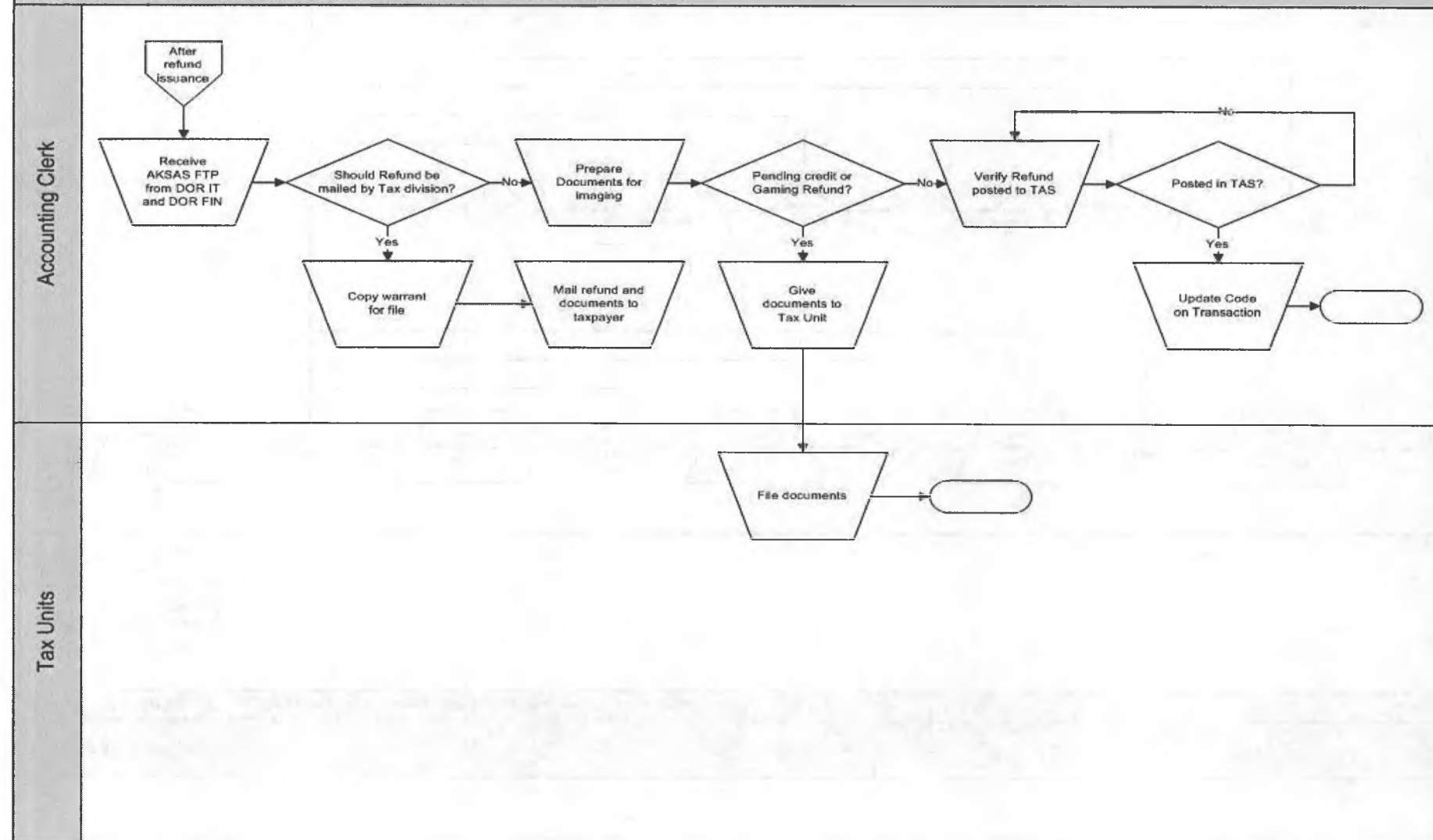
Accounting Technician



E. 25

Refund – After Issuance

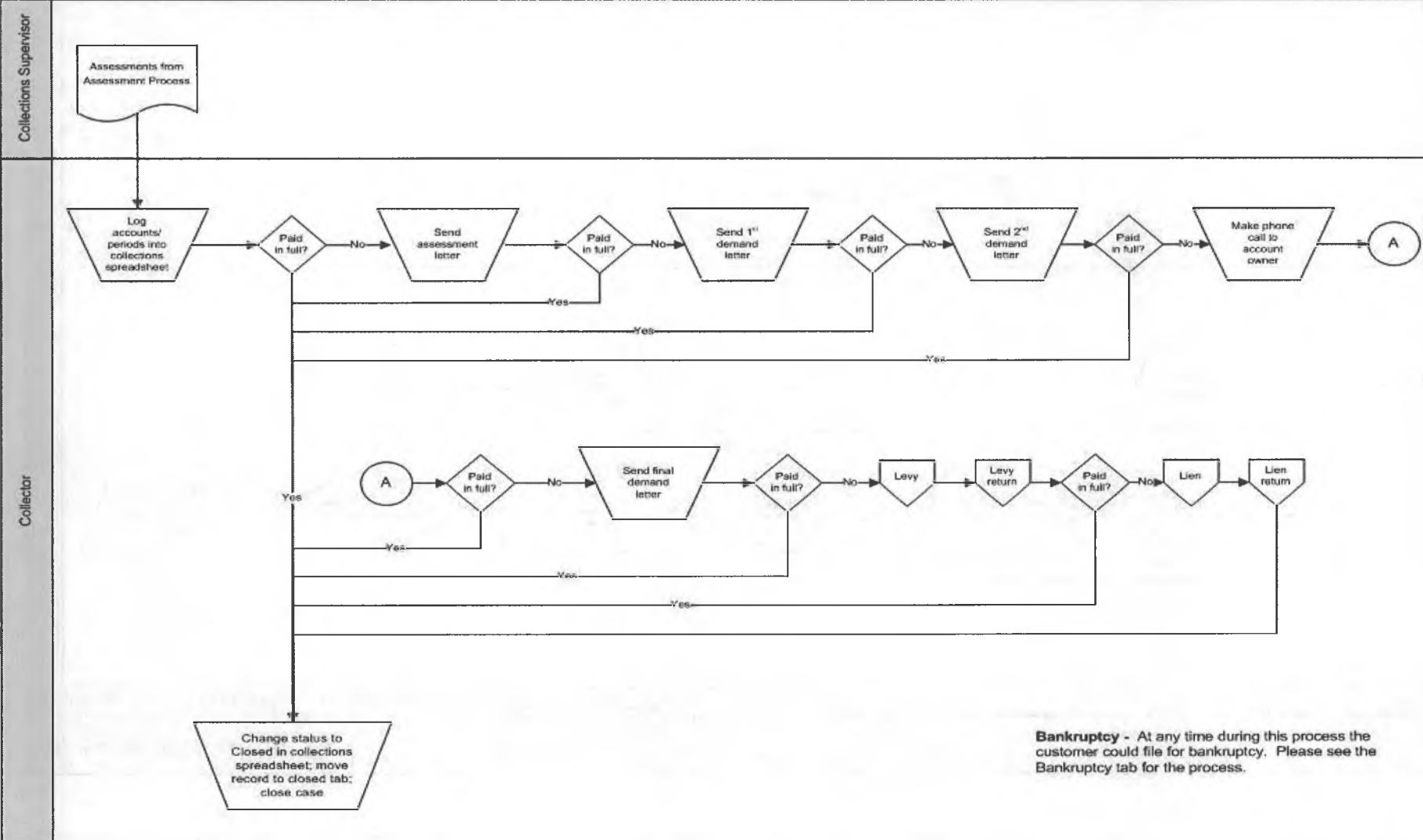
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 26

Collections Overview

STATE OF ALASKA - Tax Revenue & Information Management System Plan



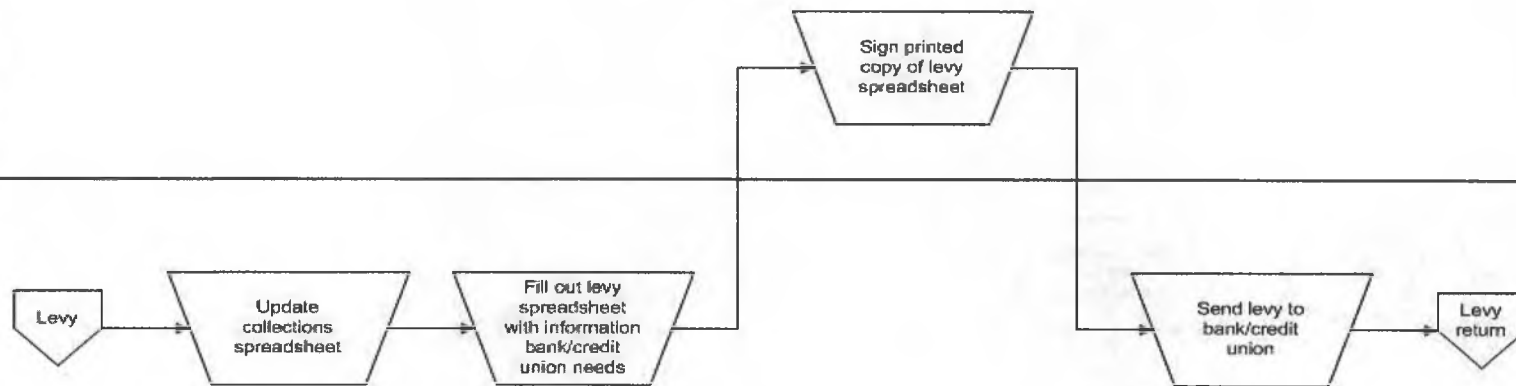
E. 27

Collections - Levy

STATE OF ALASKA - Tax Revenue & Information Management System Plan

Collections Supervisor

Collector

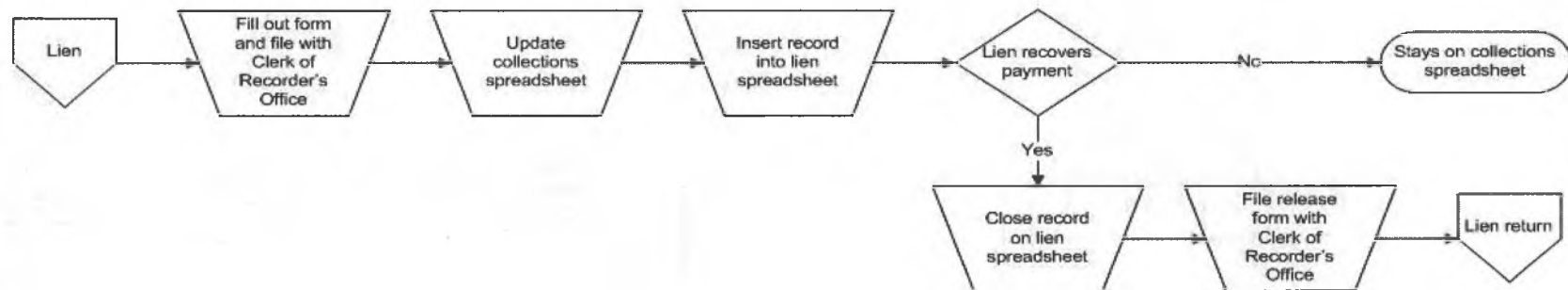


E. 28

Collections – Lien

STATE OF ALASKA - Tax Revenue & Information Management System Plan

Collector

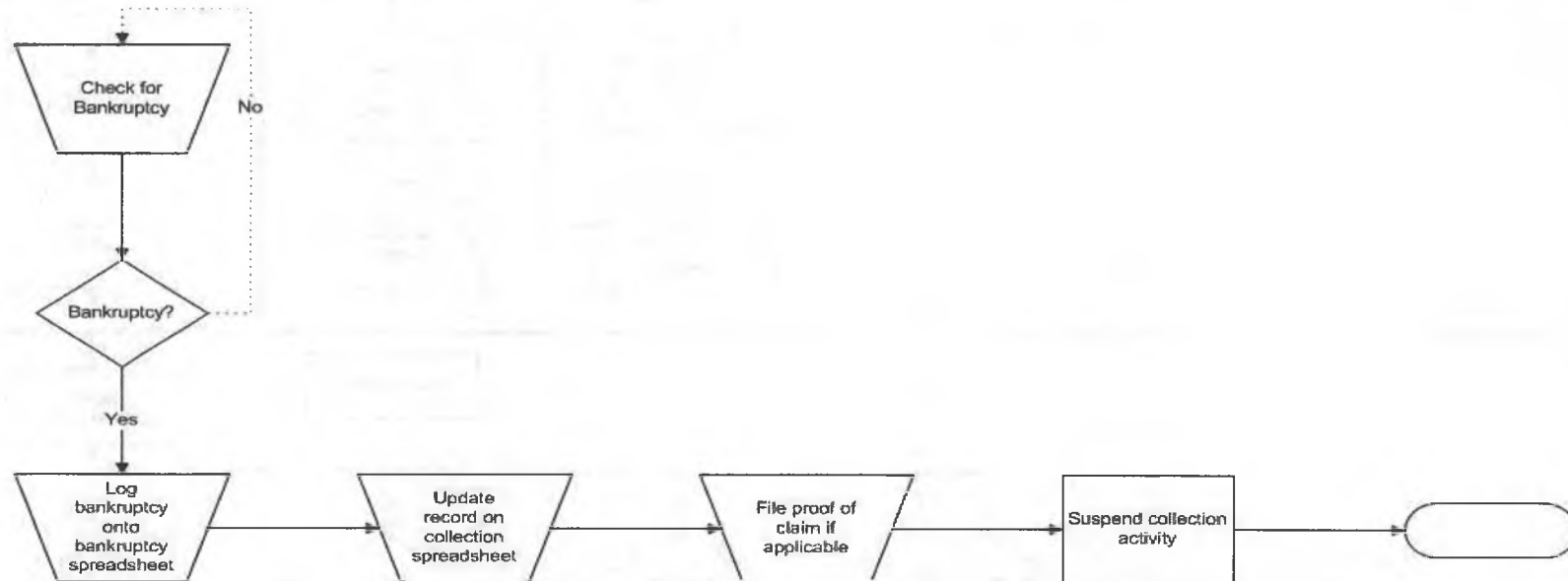


E. 29

Collections - Bankruptcy

STATE OF ALASKA - Tax Revenue & Information Management System Plan

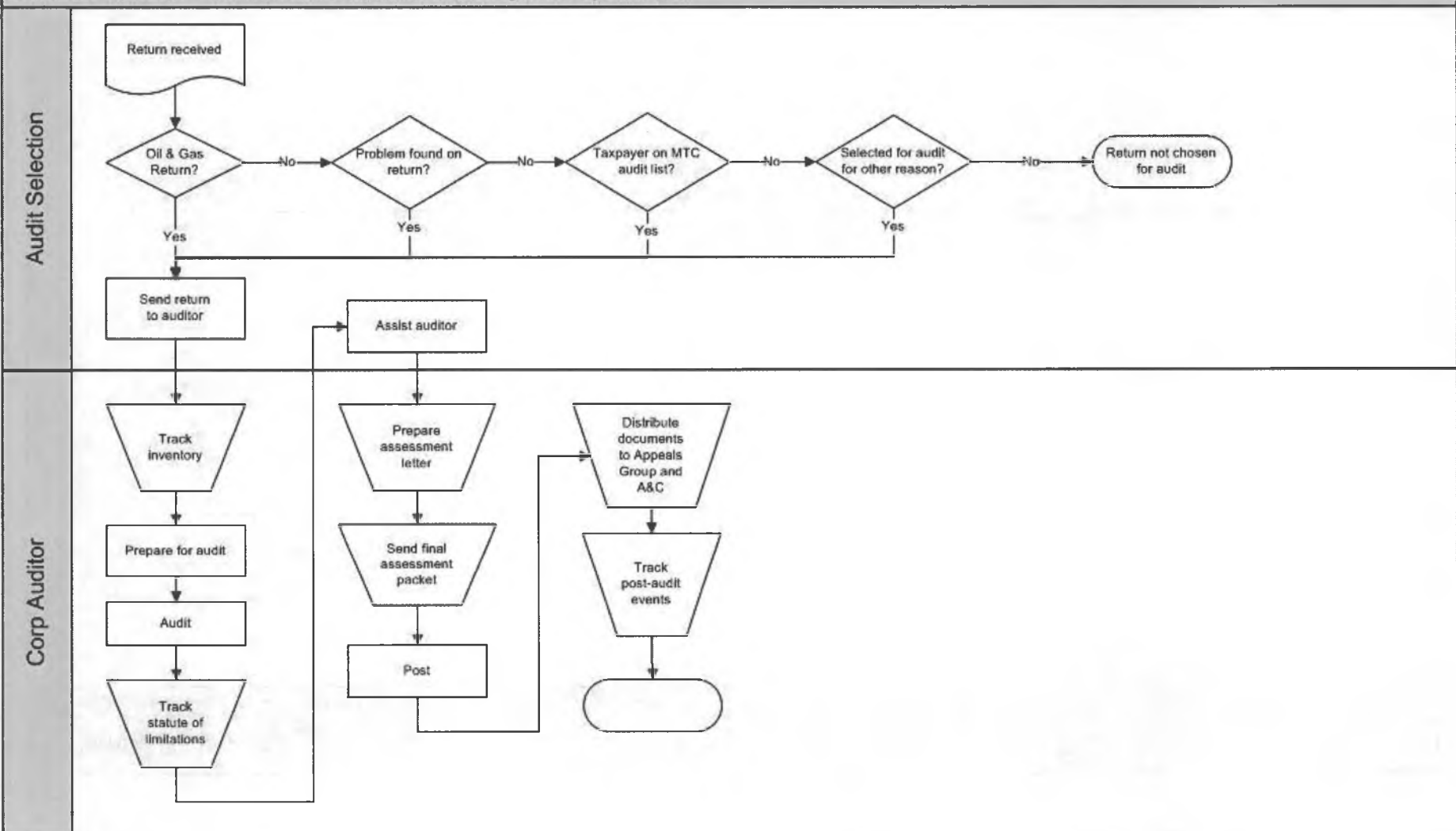
Collector



E. 30

Audit Processing – Corp

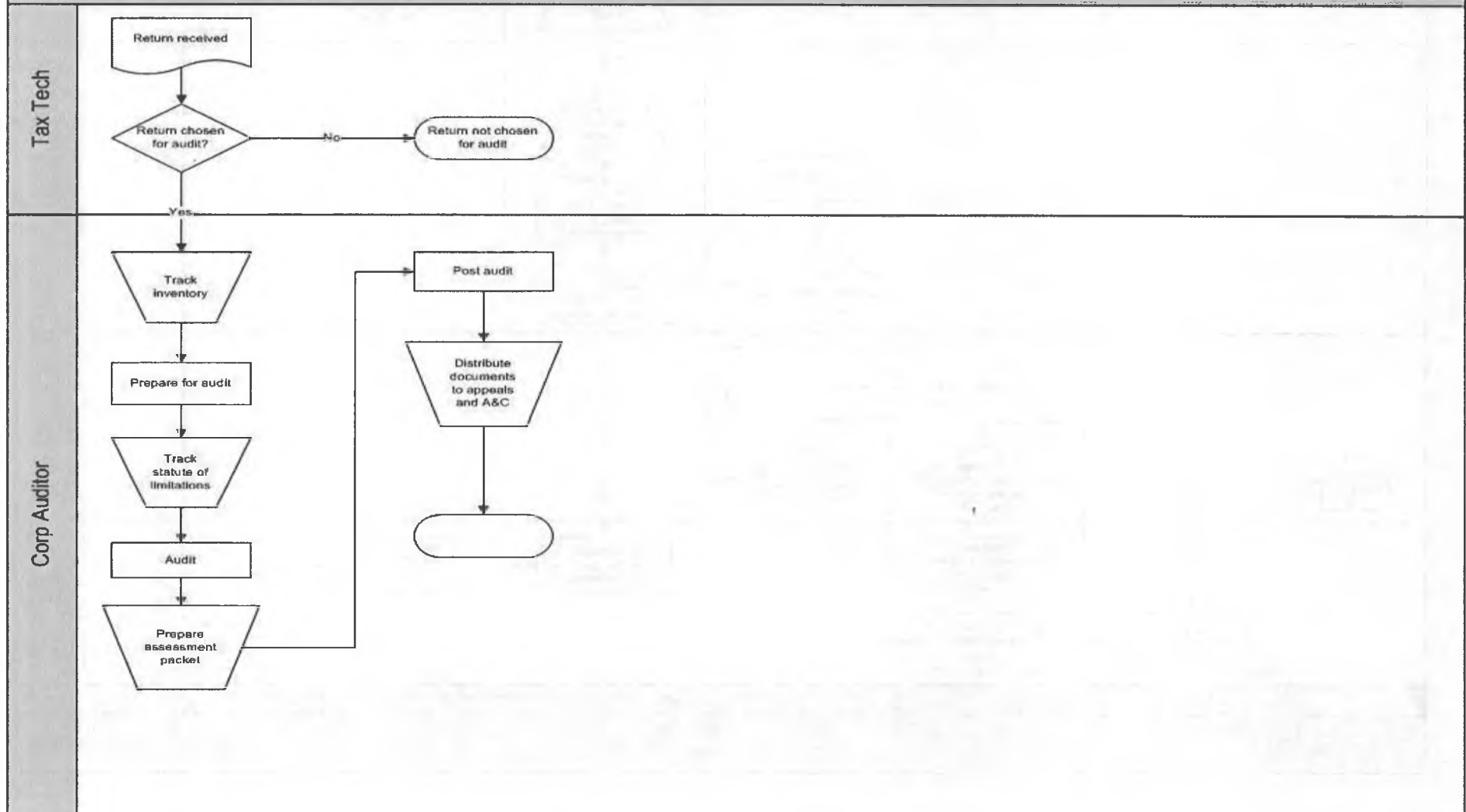
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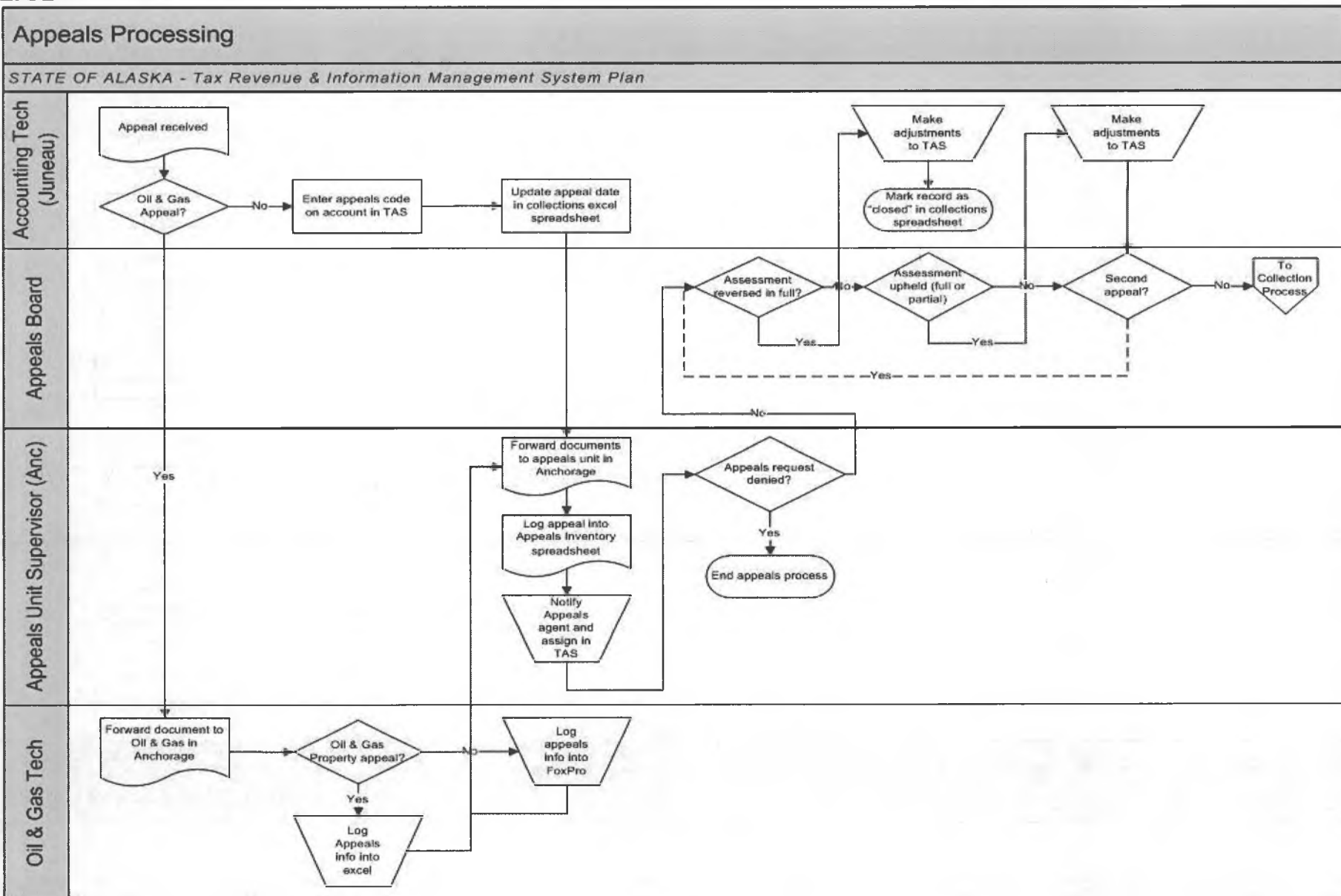
E. 31

Audit - Motor Fuel & Mining

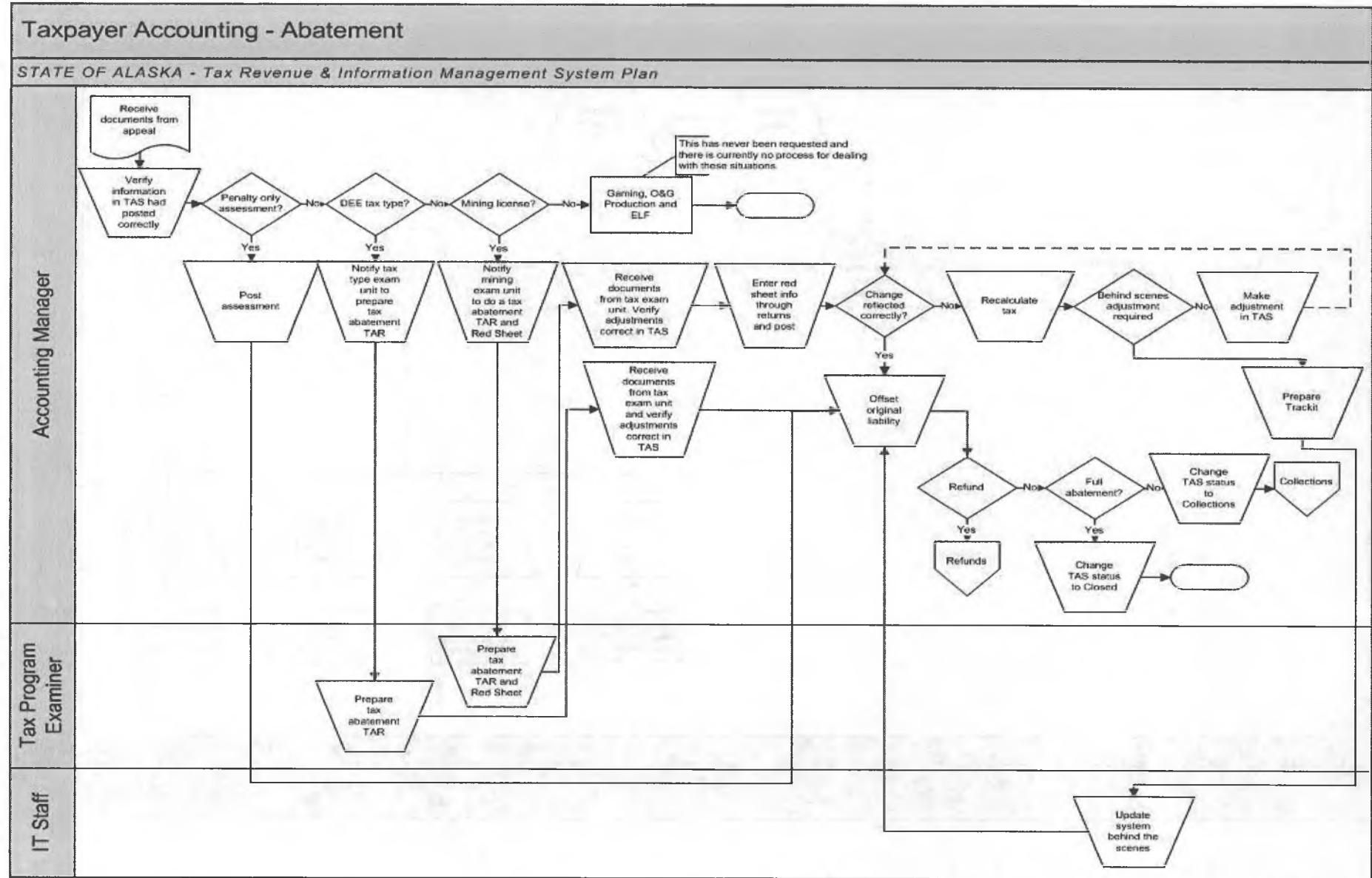
STATE OF ALASKA - Tax Revenue & Information Management System Plan



E. 32



E. 33

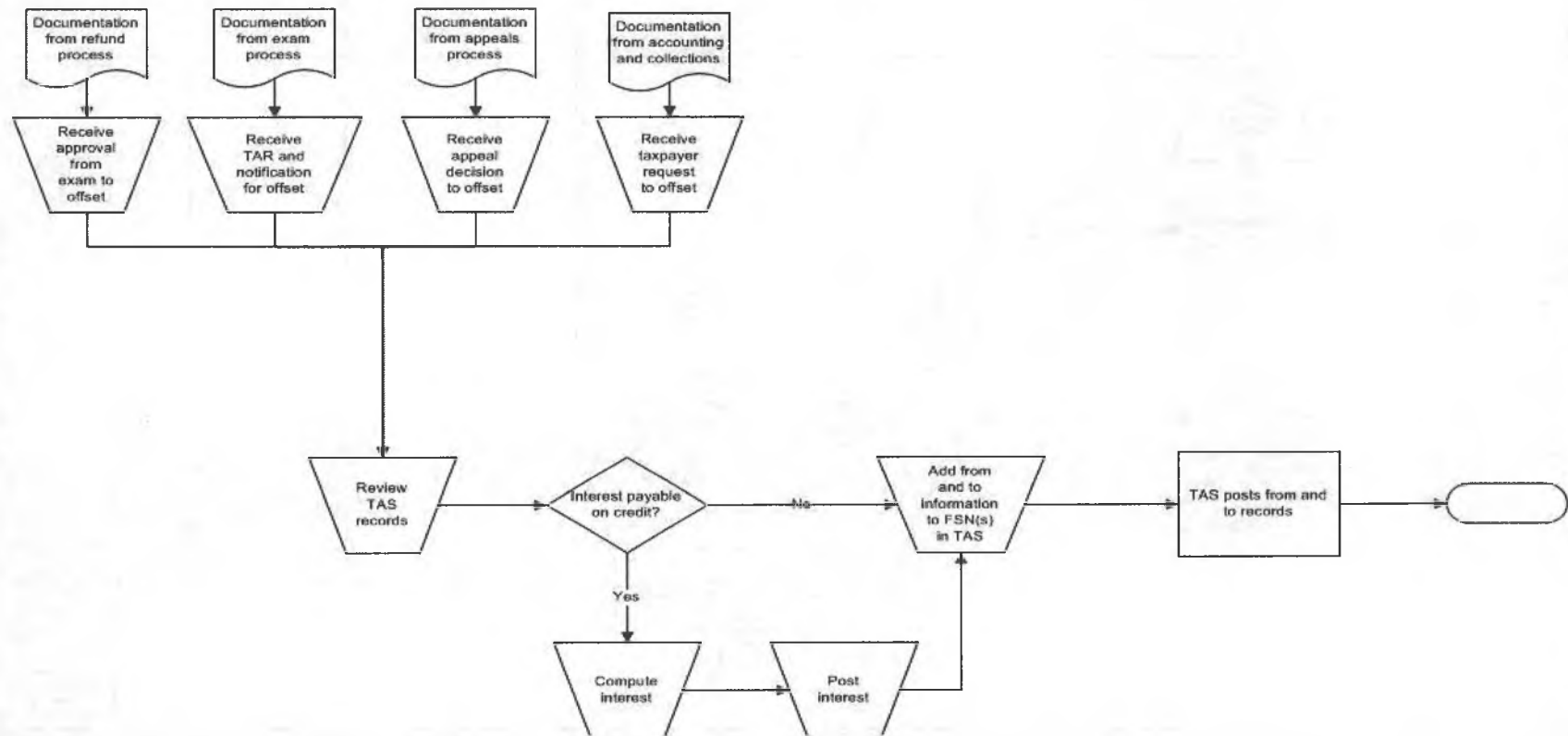


E. 34

Taxpayer Accounting - Offsets

STATE OF ALASKA - Tax Revenue & Information Management System Plan

Accounting Manager

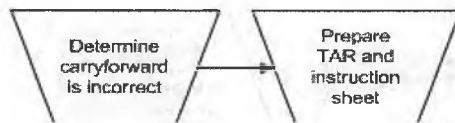


E. 35

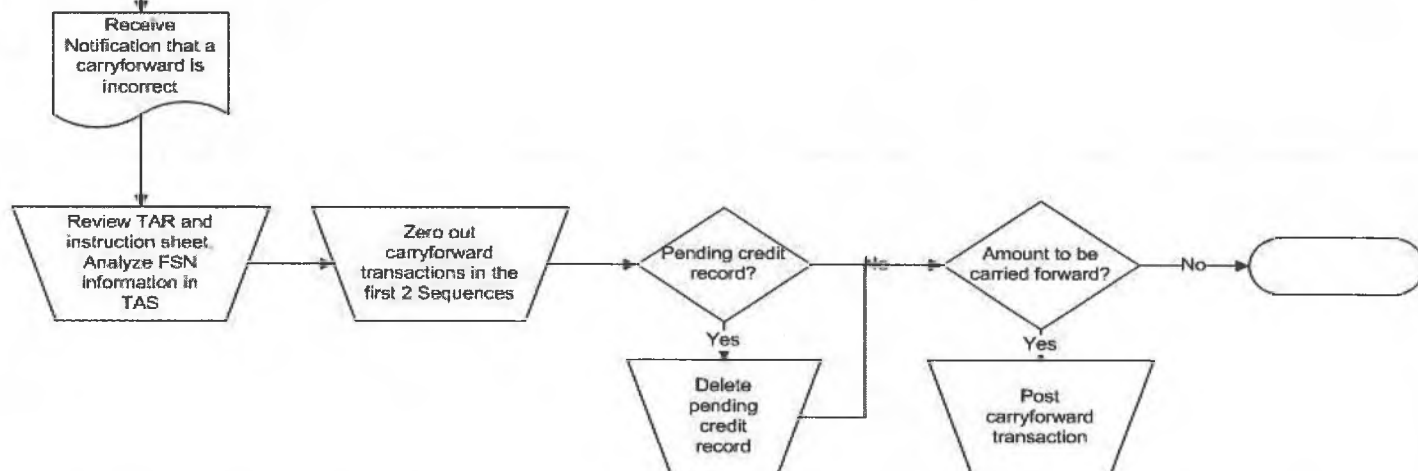
Taxpayer Accounting – Reverse CarryForward

STATE OF ALASKA - Tax Revenue & Information Management System Plan

Tax Program Staff



Accounting Manager



Carryforward reversals are primarily required for fixing corporate income tax accounts because DEE Corp is programmed to generate a TAS carryforward transaction after posting in DEE, even if incorrect. In order to reflect the reversal of the carryforward, a TAR is required.

E. 36

Taxpayer Accounting – Correct Effective Date

STATE OF ALASKA - Tax Revenue & Information Management System Plan

Corporation Tax Examiner

Determine
carryforward
effective date
needs to be
corrected

Accounting Manager

Receive notification
to change
carryforward effective
date

Review TAS and
verify that decision
to change the
effective date is
applicable

Change effective
date on FSN

Change effective
date on PC record

Recalculate
interest on FSN

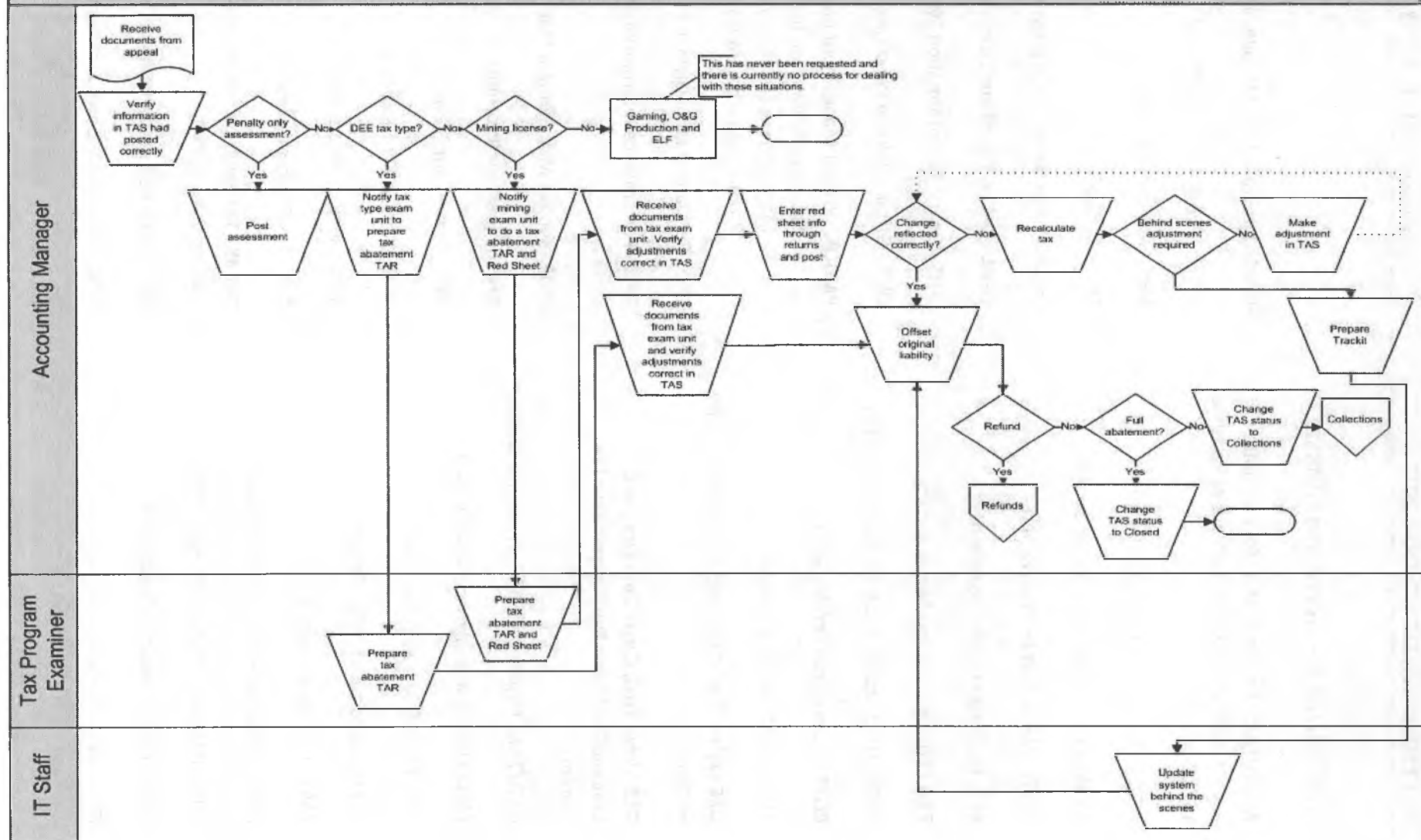
Ensure
transactions
posted correctly

Fix effective date is a manual process and is required when a carryforward (as requested by taxpayer) is posted and all or part of the carryforward is attributable to a payment (for the tax year) that was received after the payment due date for that year.

E. 37

Taxpayer Accounting - Abatement

STATE OF ALASKA - Tax Revenue & Information Management System Plan



APPENDIX F – Acronym Glossary

ADOR/TAX – Source citation for corporate author State of Alaska Department of Revenue Tax Division

AITG - Alaska Information Technology Group

AKSAS - Alaska State Accounting System

ASPR - Alaska Salmon Price Report

BPI - Business Process Improvement

BPR - Business Process Reengineering

CASS - USPS Coding Accuracy Support System

COTS - Commercial Off-the-Shelf

CPS - Cash Processing System

DEE Excise - Data Entry and Examination Excise System

DEE Motor Fuel/Corp - Data Entry and Examination Motor Fuel/Corporation Tax System

DOR/TAX - Department of Revenue Tax Division

EBN - Electronic Bankruptcy Notification

EDI - Electronic Data Interchange

EMR - Economic Monthly Report

FAST - Fast Enterprises, LLC

FHWA - Federal Highway Administration

IFTA - International Fuel Tax Agreement

IMF - Federal Individual Master File

IRP - International Registration Plan

ITMS - Integrated Tax Management System

MBP - Multiple Beneficiary Permittees

MeF - Modernized e-File

MS - Microsoft

OLAP - Online Analytical Processing Model

OPAL - Online Permit and License

OTIS - Online Tax Information System

OVR - Offtake Volume Reporting

PMBOK - Project Management Body of Knowledge, Standard for Project Management created by Project Management Institute

PFD - Permanent Fund Dividend

PIPS - Performance Information Procurement System

PMP - Project Management Plan

RFI - Request for Information

RFP - Request for Proposal

SAN - Storage Area Network

SME - Subject Matter Experts

TAS - Tax Processing System

TRIMS - Tax Revenue and Information Management System

UP - Unclaimed Property Viewer

WBS - Work Breakdown Structure

9.

**Single Audit of
the State of
Alaska**

Feb. 28, 2011

ALASKA STATE LEGISLATURE

LEGISLATIVE BUDGET AND AUDIT COMMITTEE

Division of Legislative Audit



P.O. Box 113300
Juneau, AK 99811-3300
(907) 465-3830
FAX (907) 465-2347
legaudit@legis.state.ak.us

February 28, 2011

Honorable Members of the
Alaska State Legislature

The Honorable Sean Parnell
Governor
State of Alaska

The Honorable Daniel R. Levinson
Inspector General
Office of the Inspector General
U.S. Department of Health and Human Services

We are pleased to transmit the Single Audit of the State of Alaska for the fiscal year ended June 30, 2010. The audit was conducted in accordance with auditing standards generally accepted in the United States of America; *Government Auditing Standards* issued by the Comptroller General of the United States, and complies with the federal Single Audit Act Amendments of 1996 and the related *OMB Circular A-133* issued by the U.S. Office of Management and Budget.

The report includes an opinion on the basic financial statements of the State of Alaska for FY 10, recommendations on financial and compliance matters, and required auditor's reports on internal controls and compliance, and the Schedule of Expenditures of Federal Awards.

The findings and recommendations included in this report are organized by department and include prior financial/compliance findings not fully corrected by the departments. Our FY 09 Single Audit contained 25 recommendations; this report presents a total of 30 recommendations, eight of which were presented at least in part last year. Included in this year's recommendations are four recommendations made to Alaska Housing Finance Corporation whose audit was performed by other auditors. With your active support and encouragement, we hope to continue seeing improvement in the implementation of these recommendations by the state agencies.

Members of the Legislature
The Honorable Sean Parnell
The Honorable Daniel R. Levinson

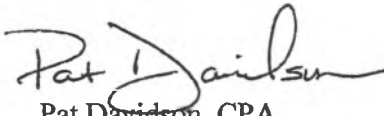
- 2 -

February 28, 2011

We would again like to acknowledge the professional assistance and cooperation of the Department of Administration's Division of Finance. The division has a strong professional commitment to excellence in the financial accounting and reporting for the State of Alaska. Its continued efforts towards resolving statewide accounting and reporting concerns are commendable.

We would also like to acknowledge the cooperation of all other state agencies involved during the conduct of this audit.

The dedicated staff of the Division of Legislative Audit remains committed to improving the financial accountability of the State of Alaska. Your active involvement is critical to improving that accountability. We are available to assist you in that effort.


Pat Davidson, CPA
Legislative Auditor

DEPARTMENT OF REVENUE

One recommendation was made to the Department of Revenue (DOR) in the *State of Alaska, Single Audit for the Fiscal Year Ended June 30, 2009*. Prior year Recommendation No. 2 is not resolved and is reiterated in this report as Recommendation No. 4.

No new recommendations have been made during the FY 10 statewide single audit.

Recommendation No. 4

DOR's commissioner should ensure staff within its Tax Division implement controls to improve the auditing of oil and gas severance tax revenues.

Prior Finding

In FY 08 and FY 09 significant deficiencies in controls were reported over the auditing of severance tax revenues by DOR's Tax Division. Control deficiencies included insufficient audit oversight, a lack of standard procedures to guide the audit process, inadequate reviews of audits, and untimely reviews and reconciliations of tax returns.

Title 43 of the Alaska Statutes gives DOR the authority to collect tax revenues for the State and to ascertain the correctness of such revenues. The department's main tool for ascertaining the correctness of severance tax revenues is its Tax Division audit section. There are no statutory requirements that DOR's tax auditors conduct their audits in accordance with industry audit standards such as those issued by the American Institute of Certified Public Accountants or the Government Accountability Office. Historically, DOR's audit section has relied upon standard audit programs and supervisor review and oversight to ensure that their audits are timely, accurate and that audit results can withstand the scrutiny of the administrative appeal process and, in some cases, litigation.

With the passage of PPT² and ACES³ legislation, management's controls over the auditing of severance taxes deteriorated. The new laws are more complex to audit. The hiring and retention of experienced, competent audit staff has proven challenging. Delays in drafting PPT and ACES regulations have further disrupted the audit process.

Legislative Audit's Current Position

Significant control deficiencies continued over the auditing of oil and gas severance tax revenues in FY 10. A loss of experienced audit staff during FY 10 compounded the struggles that the audit section was already experiencing.

Our review of DOR's oil and gas severance tax audits and inquiries with DOR staff noted the following deficiencies:

- The division continues to conduct audits without developing standard processes including audit plans and procedures.
- A significant portion of an audit's methodology and results were insufficiently documented.
- The deficiencies in audit documentation forced the tax section to issue a less detailed report than what is issued as part of their standard report format.

²*Petroleum Profits Tax* (enacted in August 2006).

³*Alaska's Clear and Equitable Share* (enacted in November 2007).

- Audit supervisors did not review and approve audit methodology prior to audits being conducted.
- Audit supervisory reviews were limited, sporadically documented, and only conducted at the end of the audit.

Oil and gas severance taxes, totaling approximately \$2.6 billion in FY 10, are a significant source of revenue for the State of Alaska. Insufficient internal controls over the auditing of severance tax revenue may result in the loss of revenue and increase the risk that tax revenue assessments will not hold upon appeal.

We recommend that DOR's commissioner take action to ensure that Tax Division management improves controls over the auditing of severance tax revenues. Specifically, standardized audit processes should be developed and implemented. Auditors also need more oversight and timely feedback during the audit process.

Agency Response – Department of Revenue

Item 1: *The division continues to conduct audits without developing standard processes including audit plans and procedures.*

Response: *We disagree. The division is, and has been, in the process of developing standard processes including audit plans and procedures. Development of standard processes is an ongoing project. As you are aware, the legislature significantly changed the way oil and gas production tax is calculated with the passage of the Petroleum Profits Tax (PPT) in 2006. In 2007, the legislature made further changes to the production tax through the passage of Alaska's Clear and Equitable Share (ACES) legislation. These two major pieces of legislation completely overhauled the production tax scheme and instituted a new tax credit program. The Division has worked diligently over the last four years to implement the changes while continuing to work on audits of tax returns filed under the previous tax structure. Implementation includes not only developing standard processes, but also drafting regulations, hiring and training new auditors, developing tax return forms, establishing tax credit audit and examination procedures, educating taxpayers, and various other duties that accompany the implementation of what is basically a new tax program. You are aware that the oil and gas production tax is administered without automated systems. This means that all processes are performed manually which further strains the Tax Division's limited resources. Although development of standard processes is not yet complete, this does not mean that the Division is not and has not been working on developing those processes.*

Item 2: *A significant portion of an audit's methodology and results were insufficiently documented.*

Response: *We agree. The audit in question was started by a highly experienced individual who retired a few months after the audit was opened. The audit was then*

transferred to another senior auditor who resigned his position before the audit was completed. The audit was transferred yet again to another senior auditor who had to quickly familiarize himself with all issues within the audit and complete the audit within a short period of time. As stated above, oil and gas production tax audits are conducted without the assistance of automated systems. All audit work, including transaction sampling and testing, is performed manually. Data for this particular audit included over 2 million documents with thousands of transactions per document. During the course of the audit, the auditors manually tested over 1 million transactions. The time it took to perform the manual testing caused the auditor to run out of time to complete proper documentation of audit findings prior to expiration of the statute of limitations. The Tax Division took the position that it was in the best interest of the state to issue the audit with insufficient documentation and with a less detailed audit report than to miss the statute of limitations and, in effect, issue no audit at all. The auditor was instructed to issue the audit, but continue to document audit findings and complete the audit report after the fact. The taxpayer was informed that it would receive a more comprehensive explanation of our adjustments at a later date.

Item 3: The deficiencies in audit documentation forced the tax section to issue a less detailed report than what is issued as part of their standard report format.

Response: We agree. See explanation under Item 2, above.

Item 4: Audit supervisors did not review and approve audit methodology prior to audits being conducted.

Response: We agree, but disagree that this is an issue. It is not common practice for the Tax Division to approve audit methodology prior to audits being conducted. Audits are assigned to auditors based on their level of experience and their job class. Audits of the largest oil and gas production taxpayers are assigned to Oil and Gas Revenue Auditor IV's (OGRA IV). Under the class specifications, OGRA IV's "serve as lead auditor having complete responsibility for the largest oil and gas production tax . . . audits." The particular audit in question was assigned to an OGRA IV who was required to perform the audit with no day-to-day oversight. Audit methodology is at the auditor's discretion provided, however, that the end result is that the auditor has accurately evaluated tax liabilities. As stated previously in this letter, the Tax Division is still implementing what is essentially a new tax program and specific audit methodology has not yet been defined for these audits.

Item 5: Audit supervisory reviews were limited, sporadically documented, and only conducted at the end of the audit.

Response: We agree. Audit reviews in all programs are conducted at the end of audits. That is common practice in all audits in the audit profession. We also agree that supervisory reviews were limited and sporadically documented in some of the audits closed during the fiscal year. Again, this was due to the continual implementation of PPT, ACES and the new credit program. Implementation has put a strain on audit resources. Money requested to continue contract audits has been reduced which put further strain on our resources.

However, management continually communicates with staff on tax issues via meetings and emails, and has discussions about the proper application of statutes and regulations. As a result of the poor documentation of the audit identified in issues 2 and 3, management has instituted the practice of meeting with the audit leads and team members on the largest audits at least once a month to discuss the progress of the audit and any issues that may have arisen that require management input.

The bulk of the findings in the audit report are attributable to:

- staff turnover, particularly at the supervisory level;*
- the inability to recruit senior level auditors at current pay levels, despite intensive recruitment efforts over the last two years; this means (1) less experienced auditors are working major audits, and (2) supervisors are having to spend time conducting complex audits, instead of using that time to supervise and developing audit manuals, processes and procedures; and*
- lack of automated tax processing systems to manage and share information; this dramatically increases the amount of time needed to complete audits and review returns, and thus, siphons resources away from program development.*

As junior auditors in the Production Tax Audit Group gain experience, they will be able to take on more complex and higher volume audit work. This should relieve some of the resource strain, provided these auditors continue working for the Department once they reach senior levels. Over the last three years, great efforts have been made by the Department to obtain an automated tax processing system to manage and share information, but funding for this project has not yet been forthcoming.

*Contact Person: Ginger Blaisdell, Director
 Administrative Services Division
 Telephone: (907) 465-2312*

Legislative Auditor's Additional Comments

We reviewed DOR's response and nothing in the response persuades us to revise the recommendation.

10.

**"State Tax
Policy and Oil
Production"**

still – but it is still clear that in the absence of such an alternative policy, a higher gas tax would clearly boost economic efficiency.

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Chapter Nine from U.S. Energy Tax Policy

Edited by

Gilbert E. Metcalf

Tufts University, Massachusetts

Cambridge University Press

NINE

State Tax Policy and Oil Production

The Role of the Severance Tax and Credits for Drilling Expenses

Ujjayant Chakravorty, Shelby Gerking, and Andrew Leach

9.1 Introduction

Although most energy-producing states have levied taxes on the value of oil, natural gas, and coal production for many years, changes in these taxes have become headline news as state governments grapple with budget shortfalls brought about by the current recession. For instance, Alaska has increased the severance tax on the value of its oil production and attempted to stimulate future production by allowing a credit against this tax for expenditures on capital items, including drilling rigs, infrastructure, exploration, and facility expansion (Alaska Department of Revenue 2008). In late 2008, California Governor Arnold Schwarzenegger proposed levying a 9.9 percent production tax on the value of most onshore oil production to help close a projected \$24 billion budget deficit, but he subsequently reversed his position (Casselman 2009; Skelton 2009). The Pennsylvania legislature is considering a proposal to levy a 5 percent tax on the value of natural gas produced from the giant Marcellus shale deposit, but the bill is opposed by industry leaders who contend that it would result in 30 percent less drilling as well as revenue reductions to state and local governments totaling \$880 million over the next decade (George 2009).

These measures, both enacted and proposed, raise a number of long-standing and important questions about the effects of state energy taxes that go well beyond their potential to provide a solid revenue base to support public services. Given the overlapping tax bases claimed by states and the federal government, to what extent do state energy tax increases result in lower collections of federal tax revenues, including the federal corporate income tax? Do state energy taxes restrict production and encourage “high-grading” of energy reserves and by how much? Do state taxes tilt the time path of energy production to the present or to the future? How do upstream

subsidies for exploration and development work together with downstream taxes on production to influence the levels and time paths of production and tax collections? What are the implications of these taxes for the long-run sustainable use of nonrenewable natural resources? The analysis in this chapter bears directly on these questions. It also serves as a basis to examine proposed changes in federal tax policy, including the elimination of the percentage depletion allowance and the expensing of intangible drilling costs.

We adapt the Hotelling model developed by Pindyck (1978) to examine how a state's taxes and subsidies at different stages of resource exploration and production alter the behavior of oil producers and thus impact on exploration activity, additions to the reserve base, and the production of energy. In our model, returns to exploration are subject to diminishing returns, and the cost of production is affected both by the level of reserves and the level of output. Producers located in a given state are assumed to produce only a small fraction of world output and therefore face an exogenously determined price of oil. We calibrate the model using data from U.S. oil fields to evaluate the effects of alternative tax and subsidy policies on drilling and production, on tax revenue accruing to states and to the federal government, as well as on the time path of drilling expenditures and resource production.

A key result from the calibrated model is that oil production is closely linked to the size of the reserve base and is relatively insensitive to changes in oil prices. This outcome, which is broadly consistent with experience in the U.S. oil industry over the past 50 years, leads to the conclusion that the severance tax has little effect on production levels and serves mainly to redirect rents earned in the oil industry to the public sector. Thus, increases in severance taxes or a reduction in the subsidies provided to the oil and gas industry may lead to rent taxation and therefore have only marginal effects on the drilling and production of oil and few adverse impacts in terms of national security and increasing U.S. dependence on foreign oil.

Prior simulation studies (Deacon 1993; Kuncie et al. 2003) also have considered aspects of these issues, but a novel feature here focuses on effects of combining subsidies for exploration and development with taxes on the value of energy production. The rationale for subsidizing exploration and development is to expand the reserve base and ultimately to stimulate oil production in much the same way as an investment tax credit (see Chirinko 2000) might increase capital formation and boost output in manufacturing. As previously indicated, this type of tax policy has been adopted by Alaska, and it has been suggested as a model for other states (Headwaters Economics

2009). It may also bear on national energy tax policy in light of the interest in stimulating drilling for new reserves.¹ The simulations suggest that a drilling expense credit may cost more than the incremental severance tax revenue obtained, although such credits may be worthwhile concessions if a state's objective is to generate greater support for increasing the severance tax rate.

The remainder of the chapter is organized into six sections. Section 9.2 reviews the issue of oil taxation in twelve major oil-producing states in the United States. Section 9.3 summarizes findings from the literature regarding temporal economic effects of state energy tax policies. Section 9.4 describes the extended Pindyck (1978) model that is used as a conceptual basis for our tax policy simulations. Section 9.5 discusses the way in which the model was parameterized. Section 9.6 presents simulation results, and Section 9.7 concludes.

9.2 Overview of State Taxation of the U.S. Oil Industry

Key taxes on nonrenewable resource development levied by state and local governments can be divided into three main groups: taxes on production, property, and income. In its simplest form, the production or severance tax is levied on the gross value (or volume) of production of the resource as it is "severed" from the ground. The severance tax is the most widely adopted state tax specifically applying to the U.S. oil industry and will receive the most attention in the discussion. State and local governments also levy property taxes on the assessed (quasi market) value of equipment *above* ground and/or reserves *beneath* the ground. Income taxes are levied against the accounting net income of extraction firms. Although these taxes are generally aimed at extracting economic rents earned by producers from the sale of nonrenewable resources, their effects on production, exploration, and development can differ substantially (see Section 9.3). The discussion in this section briefly summarizes how these taxes are applied in major oil producing U.S. states and how they interact with each other and with other taxes on energy producers levied at the federal level. A more detailed

¹ At the Republican National Convention in 2008, Michael Steele, former Lieutenant Governor of Maryland and currently Chairman of the Republican National Committee, underscored his view that more exploration for energy resources is needed with his now famous line, "Drill, Baby, Drill." This sentiment was echoed by Republican Vice-Presidential nominee, Sarah Palin, who as Governor of Alaska, signed legislation granting a partial credit for drilling expenses against severance tax liabilities paid at an increased tax rate. For further details, see Ball (2008).

state-by-state survey of taxation and regulation of oil and gas production is available from the Interstate Oil and Gas Compact Commission (2007) and a more up-to-date survey can be constructed from a Lexis-Nexis search of state statutes. Hellerstein (1983) provides a useful discussion of the legal basis for state taxation of natural resources.

Table 9.1 presents data on oil production, nominal (legislated) oil severance tax rates, effective severance tax rates, and nominal corporate income tax rates for the twelve U.S. states that produced the most oil in 2007.²

As shown, production in these states ranged from a high of 397 million barrels in Texas to a low of 20 million barrels in Utah. Nominal severance tax rates varied widely across states as well. All states except California levied a severance tax against the value of production.³ As mentioned earlier, California is considering whether to adopt such a tax. In Alaska and Montana, nominal tax rates can exceed 10 percent. Other tax code features reflect important interstate differences.⁴ Severance taxes are generally levied against the "net value" of production, where each state has its own definition of this concept. Some states, such as Wyoming, tax the value of production at the wellhead (the top of the well), whereas others, like Utah, tax the value of production at the wellfoot (the bottom of the well), which in effect allows a deduction for lifting costs. Most states subtract royalty payments (computed as a percentage of gross value of production) for production on public land in computing net production value for determining severance tax liabilities (Louisiana does not). Public land royalties are relatively more important in Alaska, Colorado, New Mexico, Utah, and Wyoming than in other states owing to their large shares of publicly owned land. State energy tax codes are subject to frequent changes as well. For instance, Alaska now allows producers to take a credit against severance tax liabilities for capital expenditures used in exploration and development, whereas this feature was not available in 2007 and thus is not reflected in Table 9.1.

In New Mexico and North Dakota, the severance tax is actually the sum of two or more different levies on net production value. In Colorado, severance taxes are paid at graduated rates that depend on the gross income of operators, and in Alaska, Oklahoma, and Utah prevailing rates depend on the price of oil. In Colorado, Kansas, and Wyoming, local governments levy a substantial tax against the value of energy production. Although this tax is generally called a property tax by tax administrators, it is in

² The year 2007 is the most recent year for which effective tax rate data could be assembled (see discussion below).

³ California does levy a property tax on reserves in the ground (see below).

⁴ See footnotes to Table 9.1.

Table 9.1. Oil production (in Mbbl) and tax rates for selected U.S. states, 2007

State	Production	Severance tax		Corporate income tax rate ^o
		Nominal rate	Effective rate	
Alaska	263,595	12.25–15% ^a	12%	1.0–9.4%
California	216,778	None	None	8.84%
Colorado	23,237	2–5% ^b	0.7%	4.63%
Kansas	36,490	4.33% ^c	3.0% ^d	4.0–7.35%
Louisiana	76,651	3.125–12.50% ^d	9.4%	4.0–8.0%
Montana	34,829	15.1% ^e	8.6%	6.75%
New Mexico	58,831	7.1% ^f	7.5% ^m	4.8–7.6%
North Dakota	45,058	5.0–11.5% ^g	— ⁿ	2.6–7.05%
Oklahoma	60,952	7.0% ^h	6.9%	6.0%
Texas	396,894	4.6% ⁱ	3.1%	1.0% ^p
Utah	19,520	3.0–5.0% ^j	2.4%	5.0%
Wyoming	54,130	4.0–6.0% ^k	5.3%	None

^a Lower rate applies to fields in production less than 5 years; higher rate applies to fields in production more than 5 years.

^b Rate depends on gross income of operator and excludes county ad valorem taxes at 4–10%.

^c Excludes county ad valorem taxes of approximately 4%.

^d Tax rate of 3.125% applies only to stripper well production.

^e Rate applies to nonworking interest owners; working interest owners pay lower rates that vary by type of well.

^f Rate is the sum of oil severance tax, oil school tax, and oil conservation tax; local ad valorem taxes at approximately 1.2% are excluded.

^g Depends on the level of an oil extraction tax that varies by type of well; tax rate on stripper well production is 0%.

^h Excludes ad valorem taxes that vary by county.

ⁱ Excludes county ad valorem levies and (small) state regulatory and conservation levies.

^j Lower rate applies to first \$13/bbl; higher rate applies above \$13/bbl. Excludes county ad valorem levies; stripper well production is not subject to severance tax.

^k Stripper well production taxed at 4%; other production taxed at 6%; excludes county levies at 5.9–7.7%.

^l Effective rate is for oil and natural gas combined.

^m Effective rate is for oil and gas combined.

ⁿ Insufficient information available.

^o Tax rates depend on level of income before taxes for most states.

^p This is the rate for a gross receipts tax that replaced the corporate income tax in 2007 (see Tax Foundation 2009a).

Sources: Production data from U.S. Department of Energy (2009b). Nominal severance tax rate data from Interstate Oil and Gas Compact Commission (2007). Effective severance tax rate data are authors' calculations (see text). State corporate income tax rate data from Tax Foundation (2009a).

effect a severance tax levied by local governments. Many states have granted innumerable exemptions and credits against state severance tax liabilities for special situations that may be encountered by operators. Production from stripper wells (wells that produce fewer than ten barrels per day), for example, is taxed at lower rates in some states than is production from better producing wells. Production from wells employing secondary or tertiary recovery methods is sometimes taxed at lower rates as well.

A further complicating feature in analyzing economic effects of state severance taxes is that states and the federal government levy other types of taxes on oil producers and tax bases interact, particularly at the state and federal levels. Except for Wyoming, all of the twelve states levy a corporate income or franchise tax that applies to oil producers. Nominal rates for this tax, taken from the Tax Foundation (2009a), are shown for each state in Table 9.1. State corporate income taxes often are levied on a similar base to that used in computing federal corporate income tax liabilities, but the state tax rates generally are lower than the top federal rates for this tax, which currently are in the 35 to 40 percent range (Tax Foundation 2009b). State corporate income tax payments are deductible against federal corporate income tax liabilities, and state and local production tax payments are deductible against both. In some states, federal corporate income tax payments are deductible in computing state corporation income taxes and in others it is not. Although local governments in most of the states utilize some form of a property tax on oil and gas extraction equipment, property taxes on reserves are levied only in relatively few states such as California and Texas.

State and local tax burdens on oil producers are endlessly compared in state tax commission and legislative hearings as industry representatives make their case for more favorable tax treatment. Yet, because of variations across states in the application of severance and other taxes, a comparison of nominal tax rates is not particularly useful. A judgment based on a comparison of nominal rates that one state's severance tax, for example, is higher than that in another state might easily be reversed once the potentially numerous exemptions, credits, incentives, deductibility, and other special features of tax law are accounted for. Instead, more meaningful comparisons across states can be obtained by computing effective tax rates expressed as the ratio of revenue collected from a particular tax to the value of production. The calculation of effective tax rates fully accounts for, without enumerating, state-specific aspects of tax treatment faced by producers and facilitates comparisons between states because the value of production is used as a common denominator.

Table 9.1 presents effective severance tax rates prevailing in 2007 for the twelve most important oil-producing states. Unfortunately, information regarding severance tax collections is neither available from a single source nor published in a common format. In consequence, data on severance tax collections needed for the numerators of the effective tax rates were obtained by searching state department of revenue reports available on the Internet and by directly contacting knowledgeable people in these agencies as questions arose. Estimates of the value of production in each state were obtained by multiplying production volumes by the average prevailing price per barrel of crude oil. State production volumes were obtained from the Energy Information Administration, U.S. Department of Energy (2009b). Average wellhead prices of oil in each state were taken from the American Petroleum Institute (2009). The price and production volume data exclude oil produced in the Outer Continental Shelf (OCS) that is not subject to state taxation. As shown in Table 9.1, among states that levy a severance tax, effective tax rates in 2007 vary from 0.7 percent in Colorado to 12 percent in Alaska. Because of the many special tax code features just discussed, these rates tend to be lower than corresponding nominal tax rates.

9.3 Prior Literature

A sizable literature deals with the economic effects of the three types of taxes discussed in the previous section. It may be useful to briefly describe this work before proceeding with the theoretical structure we assume in this chapter. Discussion is limited to intertemporal issues; thus, topics such as interstate tax shifting or "tax exporting" are ignored (Gerking and Mutti 1981; McLure 1969; Metcalf 1993). The severance tax is given the most detailed treatment because it has been widely adopted and because its effects are the focus of the simulations presented in Section 9.6.

9.3.1 Production Taxation

Hotelling's (1931) seminal analytic work considers a per unit severance tax in a model with an endogenous price (net of constant extraction costs) and the total exhaustion of fixed reserves. The severance tax is found to conserve the resource by extending the time it takes to exhaust the total pool. Herfindahl (1967) extends this result with a model that features an extraction cost function that depends on output. Under competition, the severance tax is shown to tilt production to the future (i.e., delay production), thereby

extending the life of the pool. The pool is fully exhausted at a postponed terminal period.

Burness (1976) reformulates the dynamic framework by including severance tax rates that vary over time. In this model, price is exogenous, reserves are fully depleted, and extraction cost depends only on output. The general proposition derived is that the severance tax will tilt production to the future if the tax rate is held constant or rises at a rate less than the discount rate. A severance tax that rises with the discount rate will not distort the time path of production. Conrad and Hool (1984) show that introducing varying grades of the resource into the model make no difference to this result.

Levhari and Leviatan (1977) allow for an extraction cost function that depends on both current and cumulative production so that as more of the resource is extracted over time, the more it costs to produce an incremental unit. Thus, in this model, the resource may not be fully exhausted. The effect of per unit severance taxation on time to exhaustion now is ambiguous. If the resource price is constant over time, terminal time is shortened and high-grading (removing ore of the highest grade while leaving lower grade ore in the ground) may occur. Nonetheless, if tax rates vary over time, then, as Heaps (1985) demonstrates, total recovery of the resource and the economic life of the resource can either increase or decrease but in opposite directions. Because these two effects of the tax work against each other, the net impact on depletion cannot be determined.

If resource quality varies across pools but is the same within a pool, Conrad (1978, 1981) shows that mine lives are shortened and lower-quality resource is left in the ground when a per unit severance tax is levied. Krautkraemer (1990) examines the effect of production taxation in a finite reserve model when resource quality varies within a given deposit. In addition to firms choosing the rate of extraction, they also choose the marginal grade cutoff at each point in time. A production tax induces high-grading at each instant of time and not just at the end of the production program. Interestingly, a production tax reduces total resource recovery and a low-grade resource left in the ground will not be extracted, even if at some point in the future the production tax is eliminated.

Uhler (1979) includes a brief examination, for the first time, of the effects of production taxation in a model of nonrenewable natural resource extraction with both production and exploration. The possibility of exploration means that the reserve base is no longer fixed. Also, when the model allows for exploration and reserve additions, the dynamics of the process become complex and equilibrium conditions no longer have closed form solutions.

Effects of production taxation, therefore, were examined with simulations. The model was parameterized for a small oil- and gas-producing region in Alberta, Canada. When a severance tax is imposed at a constant rate, operators decrease production and exploration in all periods while the endogenous price of the resource rises.

Deacon (1993) also simulates effects of severance taxation using the model developed by Pindyck (1978) and later applied by Yücel (1986, 1989). In Deacon's formulation, the oil industry is taken to be competitive, so the time path of the resource price is treated as exogenous. In the simulations, the resource price is assumed to rise in the early years of the production program, but at a rate less than the assumed 5 percent discount rate. Similar to the analytic results derived by Burness (1976) and others in models that abstracted from exploration, the application of an *ad valorem* severance tax tilts production to the future in comparison to a no-tax base case. Over the life of the program, however, the tax reduces output, implying that an important effect of the production tax is to induce high-grading. In addition, simulations show that a production tax reduces drilling in all periods and that drilling shuts down prematurely in comparison to the no-tax case.

Kunce et al. (2003) also simulate effects of production taxation using the Pindyck (1978) framework, but they parameterize the model for a single state (Wyoming) rather than the nation as a whole, as was the case in the Deacon (1993) study. They consider the effect of doubling the state's production tax on oil extraction in a setting where oil producers are assumed to be price takers. A key feature of this study was to embed the production tax in a broader tax system that allowed for interactive tax bases and tax shifting between the local, state, and federal governments. Simulations demonstrate that a hypothetical doubling of Wyoming's production tax leads to reduced drilling and reduced oil production in each subsequent period. Estimated production declines, however, are comparatively modest; the response of production with respect to the tax change turns out to be highly inelastic (-0.06). Thus, the main effects of the tax increase would be to rather dramatically increase Wyoming's severance tax revenue and to reduce federal corporate income taxes paid by producers.

9.3.2 Property Taxation

Taxation of property, specifically reserves, has received little attention in the literature on production from nonrenewable resources. One reason for this may be the practical complexity of levying such taxes. Nonetheless, Hotelling (1931) demonstrates that a constant percentage tax on the value of reserves

will induce firms to extract more rapidly as they attempt to "mine out from under the tax." Conrad and Hool (1981) show that a constant tax rate per unit of reserves encourages extraction of higher-grade resource in the early periods of the program, but the cutoff grades are lower, thus extending the life of the mine. The property tax is also examined by Heaps and Helliwell (1985) in a model that allows for new reserve investment. The tax is shown to tilt production to the present and to reduce investment in new deposits to avoid holding costs. Simulations by Gamponia and Mendelsohn (1985) show that a property tax on reserves results in tilting production to the present. Deacon (1993) obtains the same outcome in his simulation study and also confirms the Heaps and Helliwell (1985) result by showing that the property tax on reserves results in lower levels of drilling in the early years of the program.

9.3.3 Income Taxation

Burness (1976) analyzes a profits tax on a nonrenewable resource producer with fixed reserves and concludes that output trajectories will not change when the tax is applied at a constant rate. If the tax rate increases over time, however, firms will speed up depletion of the fixed reserve. Conrad and Hool (1984) model a progressive profits tax, finding that such a tax will not exhibit the neutrality of a flat rate profits tax with regard to the extraction path and grade selection. Deacon (1993) simulates a structure broadly similar to federal corporate income taxation with expensing of current and capitalized drilling costs. Simulated paths of extraction, drilling effort and reserves show little distortion from the no-tax base case. These results suggest that income taxation is the least distortionary among the three types of energy taxes imposed by U.S. states.

9.4 Conceptual Framework

We propose a simple dynamic model in the tradition of Hotelling (1931) and Pindyck (1978) with some modifications. The idea is to examine the producers' response when states or a social planner imposes a menu of taxes and subsidies on oil production. We consider three tax/subsidy instruments – a severance tax, a corporate income tax, and a subsidy on drilling expenditures. Producers choose the optimal amount of drilling (and therefore reserve additions) and production of oil to maximize profits.

The model is dynamic, with a known discount rate and no uncertainty. Resource producers face an output price of the commodity that is

exogenously determined. Ideally, output prices should be endogenously determined through the process of dynamic optimization, as in Pindyck (1978). However, because our goal is to examine the effect of various tax regimes under assumptions of alternative petroleum prices and a single U.S. state produces only a small fraction of world output, the exogenous price assumption may be a reasonable approximation. In any case, a partial equilibrium model with endogenous prices may leave too many factors that critically affect oil prices out of the model (e.g., international financial markets, world economic growth).

Let the output price of petroleum be given by $p(t)$ where the argument t denotes time. Then the social planner imposes a set of taxes $(1 - \alpha_p)$ such that the net price received by the producer is the fraction α_p times the price.⁵ Thus, the production revenue accruing to producers of energy is given by $\alpha_p p q$ where q is the quantity of oil sold by the producer. We assume that whatever is extracted is sold – there is no storage.

Because we distinguish between production and exploration, we define reserves R at any given time t and the cumulative addition to the stock of petroleum given by x . The relationship between stocks and reserves is given by the differential equation

$$\dot{R}(t) = f(w, x) - q \quad (9.1)$$

That is, the change in reserves is equal to the addition in reserves net of production, as in Pindyck (1978). The function f represents the addition to reserves as a function of drilling effort w and cumulative additions to the stock x and we assume that $f_1 > 0$; $f_{11} > 0$; $f_2 < 0$ $f_{22} > 0$ and $f_{12} < 0$. More drilling effort (w) leads to higher reserve additions, but at a decreasing rate. Higher cumulative discoveries x cause current reserve additions to decline (at a decreasing rate). It is more difficult to add to the reserve base, the higher the discoveries made in the past. Finally, the marginal effect of reserve additions as a function of drilling decline with increases in cumulative stock. For convenience we assume that the stock of resource grows linearly with drilling effort. However, the cost of drilling increases in a convex fashion with drilling effort, given by $k(w)$ where $k'(w) > 0$; $k''(w) \geq 0$ and $k(0) = 0$. Finally, the total cost of extraction is given by $c(q, R)$ with $c_1 > 0$, $c_2 > 0$, $c_2 < 0$, $c_{22} > 0$ and $c_{12} < 0$.⁶ That is, the total "lifting" cost increases with quantity produced – for instance,

⁵ The tax parameter α_p and two other tax parameters to be defined momentarily are empirically specified in the next section.

⁶ In Pindyck's (1978) original formulation, both average and marginal lifting costs depended on R but not on q .

as oil is extracted from greater depths – and it also decreases concavely with current reserves. This specification follows from the view that oil is produced using reserves (a form of capital) and nonreserve inputs (i.e., physical capital other than reserves and labor), so that extraction costs are positively related to output and negatively related to reserves. The cross-partial derivative c_{12} is assumed to be negative.

We introduce two other tax/subsidy parameters in this framework, namely, the portion $(1 - \alpha_c)$ of the production cost that is deductible in computing tax liabilities, so that the net production cost faced by firms is $\alpha_c c(q, R)$ and the part $(1 - \alpha_D)$ that is deductible by the firm, which implies that the net drilling cost payable by the firm is given by $\alpha_D k(w)$. The major goals in this chapter are to examine how the three different tax/subsidy policy instruments, given by α_p , α_c and α_D , affect drilling activity, reserve additions, and production, as well as to compare their corresponding revenue and welfare implications.

Finally, given a fixed discount rate $r > 0$ the social planner solves the following problem:

$$\text{Max}_{q, w, x, R} \int_0^{\infty} [\alpha_p p q - \alpha_c c(q, R) - \alpha_D k(w)] e^{-rt} dt \quad (9.2)$$

which is subject to the following equations:

$$\dot{x} = w \quad (9.3)$$

and

$$\dot{R} = f(w, x) - q \quad (9.4)$$

The current value Hamiltonian for this problem is

$$H = \alpha_p p q - \alpha_c c(q, R) - \alpha_D k(w) + \lambda w + \theta [f(w, x) - q] \quad (9.5)$$

so that the first-order conditions are given by

$$\alpha_p p \leq \alpha_c c_q + \theta (= \text{iff } q > 0) \quad (9.6)$$

$$\theta f_w \leq \alpha_D k_w - \lambda (= \text{iff } w > 0) \quad (9.7)$$

$$\dot{\lambda} = r\lambda - \theta f_x \quad (9.8)$$

$$\dot{\theta} = r\theta + \alpha_c c_R \quad (9.9)$$

along with transversality conditions not shown here. The co-state variable λ represents the shadow price of an additional unit of discovered oil. Note that the higher the cumulative discoveries, the lower the additions to reserves. Hence, the shadow price λ will be negative. The shadow price θ represents the discounted increment to profits resulting from the addition of one unit of reserves. Reserves decrease the cost of production and therefore θ should be positive.

An important implication of the model (see equation (9.6)) is that the firm will decide to produce ($q > 0$) if the discounted after-tax wellhead oil price net of marginal extraction costs exceeds the present value of future profits from an additional unit of reserves (θ).⁷ Condition (9.7) equates the marginal benefits and costs of an additional well drilled. The benefits are in the form of an increase in reserve additions, which are given by the expression θf_w . The costs are twofold: the marginal cost of drilling net of drilling subsidies denoted by the term $\alpha_D k_w$ plus the negative effect on reserve additions from an addition to the cumulative resource stock given by λ .

Equations (9.8) and (9.9) give the time path of the derivatives for the two shadow prices λ and θ . The rate of increase in the shadow price λ has two components – the discount rate r and the fact that taking out a unit of resource increases the “cost” in the future through lower marginal reserve additions. Because f_x is assumed to be negative, the first term $r\lambda$ is negative and the second term $-\theta f_x$ is positive. At least initially the latter term is likely to be large because of the high value of reserve additions, in which case $\dot{\lambda}(t)$ is likely to be positive and the value of λ , which is negative, will decline over time. In this model, then, additions to stock adversely impact reserve formation; hence, the interpretation is completely different than in the standard Hotelling model with no exploration activity. The extra cost of drilling is that it decreases the future benefit of drilling. The time path of the marginal value of a unit of reserve θ also increases at the rate of discount but is tempered by its effect on lifting costs – additions to reserves have the added benefit of helping reduce the cost of production, net of production subsidies. This is given by the negative term $\alpha_c c_R$.

In this chapter we do not focus on the analytics of this model, which is similar to the model developed by Pindyck with some key differences. The

⁷ Notice that condition (9.7) differs from the corresponding condition derived by Pindyck (1978) in that marginal lifting costs increase with increases in q . Consequently, rather than producing at some maximum rate subject to constraints given by reserve levels, geology, and technology, the firm pays attention to how its lifting costs are affected by the level of output.

main difference is that his production costs are independent of reserves, whereas in our case, production costs decline with cumulative reserves. Moreover, here the focus is on the three tax/subsidy instruments, and we show how they play different roles in influencing production and drilling behavior by firms.

9.5 Calibration of the Simulation Model

Simulations from the model developed in the previous section are constructed based on estimates of the drilling cost, lifting cost, and reserve additions equations, specifying values for the tax/subsidy and other parameters.

9.5.1 Equation Estimates

Estimation of $k(w)$ and $f(w, x)$ are treated together because they are used to compute the marginal cost of reserve additions (k_w/f_w), a key relationship in the model described above. Drilling cost per foot is assumed to be linearly related to footage drilled, as shown in equation (9.10):

$$k(w)/w = \phi w + u \quad (9.10)$$

where ϕ is the parameter to be estimated and the disturbance term u is normally distributed. This specification ensures that the marginal cost of drilling is positive and increasing in footage drilled as long as $\phi > 0$. Using annual data for the United States from 1959 to 2007, with drilling cost per foot measured in year 2000 dollars and footage drilled measured in millions of feet, the least squares estimate of ϕ is 1.23 with t-statistic of 8.17.⁸

The production function for gross reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta \cdot x} e^v \quad (9.11)$$

where A , ρ , and β are parameters to be estimated and the disturbance term e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . Equation (9.11) is similar to the one describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978). The idea behind this equation is that the marginal product of drilling declines as footage drilled accumulates. Estimation of equation (9.11) used annual data from seven important oil-producing U.S. states (California, Kansas,

Louisiana, New Mexico, Oklahoma, Texas, and Wyoming) for which complete information on the requisite variables was assembled for the period 1970–97.⁹ Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The footage drilled variable was defined as in equation (9.10) and the cumulative footage variable was created by adding year-by-year over the sample period for each state. After taking natural logarithms of equation (9.11) and with state-effects included, we obtain least squares estimates of $\rho = 0.95$ (t-statistic = 14.18) and $\beta = 0.000437$ (t-statistic = 1.37). The value of A (28.78) was selected so that the equation predicted U.S. reserve additions in 2007. This equation shows that the marginal product of drilling (f_w) decreases with footage drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.

Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for the United States with a Cobb-Douglas functional form using methods described in Deacon (1993). Results show that if the output elasticity of nonreserve inputs is 0.35, then for 2007, $C/q = 458.1(q/R)^{1.86}$. The value of 458.1 is selected so that the right-hand side will predict average U.S. operating cost per barrel in 2007 of \$7.56.¹⁰ Note that the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and fall as production declines.

9.5.2 Specification of Tax/Subsidy Parameters

Values for the parameters α_j ($j = p, c, D$) were specified by choosing representative rates of state and federal taxes faced by oil producers and then inserting these values into equations (9.12) through (9.14).

$$\alpha_p = (1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\gamma \quad (9.12)$$

$$\alpha_c = (1 - \tau_{us})(1 - \tau_s) \quad (9.13)$$

$$\alpha_D = \{(1 - \tau_{us}\eta - (1 - \tau_{us})\delta)\} \quad (9.14)$$

In equations (9.12), (9.13), and (9.14), τ_{us} denotes the federal corporate income tax rate, τ_s is the state corporate income tax rate, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p is the

⁸ Data were taken from American Petroleum Institute (2009).

⁹ Data were taken from American Petroleum Institute (various years).

¹⁰ Data were taken from U.S. Department of Energy (2009a).

state severance tax rate, and δ represents the percentage of drilling costs that may be taken as a credit against state severance tax liabilities. This credit is a prominent tax code feature in Alaska. Also, γ represents the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and $\eta = e + (1 - e)f$ denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues for purposes of computing federal corporate income tax liabilities, where e is the percentage of current period drilling costs expensed for tax purposes and f is the present value of cost depletion deductions per unit of depletable expense (see Deacon 1993 for further details).

These equations do not capture all aspects of the tax code facing oil producers. Instead, they merely reflect important tax features and relationships between taxes affecting the oil industry in most states and at the federal level: (1) severance taxes are levied on the wellhead price of oil; (2) royalty payments for production on public land are deductible in computing state severance tax liabilities; (3) public land royalty payments, state severance taxes, and extraction costs are deductible in computing state corporate income tax liabilities; and (4) public land royalty payments, state severance taxes, and state corporate income taxes are deductible in computing federal corporate income taxes. Federal corporate income tax payments are adjusted because of the percentage depletion allowance and special treatment of drilling costs. These equations highlight interaction between tax bases and are more detailed than the corresponding treatment given by Moroney (1997) and Deacon et al. (1990). The equations incorporate the entire tax structure into the model, rather than simply analyzing one tax at a time as in Deacon (1993). Equations (9.12) through (9.14), however, ignore local taxes on the value of production as well as possible property taxes on reserves (levied by relatively few states). As noted in Section 9.2, state tax treatment of the oil industry is not uniform; the specification of the parameters α_j ($j = p, c, D$) would require reformulation to represent the tax structure of a particular state.

9.5.3 Values of Tax/Subsidy Parameters Used in Simulations

Four simulations of the model are considered in the following section. The base case simulation considers a situation in which no taxes are levied and no subsidies are allowed (No-tax Model A); the values for the tax parameters are $\alpha_p = 1$, $\alpha_c = 1$, $\alpha_D = 1$. The Low-tax Model B considers a situation in which the nominal severance tax rate is $\tau_p = 0.12$, the state corporate income

tax rate is $\tau_s = 0.06$, and public land royalty payments as a fraction of total production value is $\tau_r = 0.09$. These choices for state corporate income tax and severance tax rates are broadly representative of actual nominal rates for these taxes (see Table 9.1). The public land royalty payment fraction is similar to actual values for oil-producing states in the western United States (Gerking 2005). At the federal level, the effective federal corporate income tax rate is set at $\tau_{us} = 0.30$. The current nominal depletion rate of 15 percent applies to about 60 percent of U.S. oil production; thus, $\gamma = 0.09$.¹¹ The expensed portion of current period drilling costs is approximately 40 percent for the industry, and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that it is approximately 8 percent; therefore $\eta = 0.40 + (1 - 0.4) \cdot (0.08/(0.04 + 0.08)) = 0.8$. The parameter δ is set to zero. Thus, the tax policy parameters for Model B are $\alpha_p = 0.55$, $\alpha_c = 0.67$, $\alpha_D = 0.76$.

The High-tax Model C sets all taxes equal to their Model B values, except for the severance tax, which is set at $\tau_p = .25$. Hence, $\alpha_p = 0.47$, $\alpha_c = 0.67$, $\alpha_D = 0.76$. The Drilling Subsidy Model D sets all tax parameters equal to their Model C values, except that δ is set to 0.22, so that $\alpha_p = 0.47$, $\alpha_c = 0.67$, $\alpha_D = 0.61$.

9.5.4 Other Parameters

Each model uses a discount rate of $r = .04$, an oil price of $p = \$70$ per barrel, and is run for 110 periods at which point drilling all but ceases in the four models because it is no longer profitable. The initial value of reserves (R) was set to 20 billion barrels. This value approximates the quantity of proven reserves for the United States in 2007. The initial value of cumulative footage drilled was arbitrarily set to 2 billion feet, which is roughly equal to the cumulative footage for oil wells drilled in the United States in the past 30 years.

9.6 Discussion of Simulation Results

Results of simulations are obtained from solving the first-order equations of the model (equations (9.6) and (9.9)) after substituting values of the

¹¹ The percentage of production accounted for by nonintegrated independents was approximated by subtracting from unity the ratio of oil and natural gas liquids production by producers subject to USDOE financial reporting system (FRS) requirements to total oil and total natural gas liquids production. For 2007, this ratio was 0.612. Data were taken from U.S. Department of Energy (2009c, 2009d, 2009e).

Table 9.2. Selected values from solutions for the four models: Year 1

	Model A	Model B	Model C	Model D
Production in billions of barrels (q)	2.33	2.16	2.03	2.03
Drilled footage in millions of feet (w)	92.44	72.21	63.43	74.26
After-tax price per barrel received by producers ($\alpha_P P$)	\$70.00	\$38.50	\$32.90	\$32.90
After-tax marginal extraction cost of one additional barrel ($\alpha_C C_q$)	\$24.03	\$13.98	\$12.46	\$12.46
Reserve additions from drilling an additional million feet in billions of barrels (f_w)	0.0091	0.0092	0.0093	0.0092
Total reserve additions in billions of barrels (wf_w)	0.841	0.664	0.588	0.683
After-tax marginal cost of drilling one additional foot ($\alpha_D k_w$)	\$227.40	\$135.00	\$118.59	\$111.43
Beginning reserves in billions of barrels (R)	20	20	20	20
Ending reserves (R)	18.55	18.50	18.56	18.65
θ	\$45.80	\$24.50	\$20.50	\$20.50
λ	\$227.00	\$135.00	\$119.00	\$111.00

tax/subsidy parameters and specific equations for drilling costs (equation (9.10)), reserve additions (equation (9.11)), and lifting costs. Table 9.2 shows selected solution values for year 1 for the four models.

In year 1 for Model A, for example, solutions for the level of production and footage drilled are 2.3 billion barrels per year (6.4 million barrels per day) and 92.44 million feet, respectively. These values, together with initial reserves set to 20 billion barrels and $P = \$70$, imply that the marginal cost of extracting an additional barrel of oil is $c_q = \$24.03$ and the marginal cost of drilling an additional foot is \$227.40. Over the course of year 1, reserves fall because production exceeds reserve additions. The present value of future profits from an additional barrel of reserves is $\theta = \$45.80$ (see equation (9.6)), and the present value of drilling cost reductions from an additional unit of reserves is the negative of $\lambda = \$227$ (see equation (9.7)). Both of these two shadow prices steadily converge toward zero over time.

Values presented in Table 9.2 for Models B and C are interpreted similarly. In these two models, production and drilling are lower than in Model A, in part because the severance tax causes prices received by producers to fall disproportionately relative to extraction and drilling costs. In Model D, production is the same as for Model C because tax rates and initial values

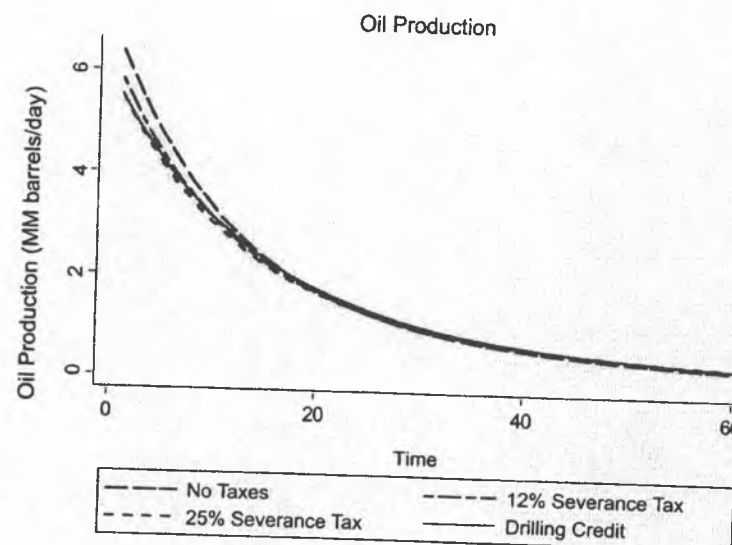


Figure 9.1. Oil production is quite insensitive to the tax structure in the U.S. case.

of reserves are the same, but footage drilled is higher because of the drilling expense subsidy. In all three models, the shadow values λ and θ converge toward zero over time, just as in Model A.

Figure 9.1 shows the time profile of oil production in millions of barrels per day for each of the four models.

In each model, production declines substantially over time. The no-tax case (Model A) shows the highest production rates. The introduction of taxes in Model B tilts production (slightly) to the future, as predicted by models of extraction from fixed reserves (see Section 9.4). Numerical calculations indicate that production rates for Model B are lower than for Model A until year 26, at which point production rates become higher for Model B than for Model A. In Model C, tilting of production to the future is more pronounced in comparison to Model A than it is for Model B because of the higher severance tax rate assumed. Production in Model C is lower in the early years of the program, but begins to exceed production in Model B by year 27. Introduction of the subsidy for drilling expenses tilts production back to the present in comparison with Model C. Model D production initially exceeds that for Model C, but is lower than that for Model C after year 48.

Figure 9.1 also shows that production is relatively insensitive to changes in tax rates and therefore to changes in prices received by operators. Cumulative production figures for the 110-year program period confirm this result (Table 9.3).

More specifically, comparing Model A with Model C, the arc elasticity of cumulative production with respect to a change in severance tax rates ($(\Delta q/q)/(\Delta \tau_p/\tau_p)$) is only $(-1.4/38.7)(0.125/0.25) = -0.02$. This outcome implies that the arc elasticity of cumulative production with respect to a change in prices received by operators is $(-1.4/38.7)(56.7/-26.6) = 0.05$. Of course, these simple elasticity calculations are based on cumulative production totals and do not take the timing of production into account, but as shown in Figure 9.1, the time path of production does not differ greatly across the four models.

Oil production also would be insensitive to changes in the percentage depletion allowance rate (η) that can be used by nonintegrated independent producers in computing federal corporate income tax liabilities. As shown in equations (9.12) through (9.14), a reduction in either η or an increase in the severance tax rate τ_p lowers α_p while leaving α_c and α_D unchanged. In fact, given the values of the tax parameters used for Models B, C, and D, eliminating the percentage depletion allowance would have the same effect on production as a four percentage point increase in the severance tax. This parallel between changes in severance tax rates and the changes in the percentage depletion allowance may be of interest in light of the Obama Administration's proposal to eliminate the latter tax preference (see Krueger 2009). Of course, changes in the severance tax and changes in the oil depletion allowance will not have equivalent effects on the collection of other taxes at the state and federal levels.

Insensitivity of oil production to severance tax increases would be to some extent expected in these simulations because a key effect of the tax simply is to reduce industry profits. The assumed price of oil (\$70/bbl) is relatively high by historical standards; thus, discounted profit is a relatively large percentage (80 percent) of discounted total revenue. In consequence, the array of taxes imposed in Model B can cut into profits without substantially altering drilling or production. Kuncie et al. (2003) found somewhat greater responsiveness of oil production to changes in severance tax rates when setting P ($P = \$23$) at a lower value than the one used in this study. In their simulations, which envision a lower ratio of profit to total revenue, the long-run elasticity of production to changes in the severance tax rate was -0.06 .

Table 9.3. Total drilling, production, tax collections, profits, and reserves for four models over the 110-year program

	Model A no taxes	Model B 12% severance tax	Model C 25% severance tax	Model D 25% severance tax with drilling subsidy
Total production (in billions of barrels)	39.4	38.5	38.0	38.6
Total footage drilled (in billions of feet)	4.5	3.9	3.6	3.9
Discounted public land royalties (in billions of dollars)	\$0	\$131.0	\$126.3	\$129.3
Discounted severance tax Collections (in billions of dollars)	\$0	\$159.0	\$319.2	\$307.5
Effective severance tax Rate	0	0.109	0.228	0.212
Discounted state corporate income tax revenue (in billions of dollars)	\$0	\$60.9	\$49.6	\$50.8
Discounted federal corporate income tax revenue (in billions of dollars)	\$0	\$230.0	\$182.5	\$188.4
Discounted depletion allowance deductions (in billions of dollars)	\$0	\$119.2	\$114.9	\$117.7
Discounted pre-tax total revenue (in billions of dollars)	\$1,544	\$1,456	\$1,403	\$1,437
Discounted extraction costs (in billions of dollars)	\$186.3	\$151.8	\$130.1	\$133.0
Discounted drilling costs (in billions of dollars)	\$125.6	\$84.4	\$68.3	\$88.3
Discounted firm profits (in billions of dollars)	\$1,231	\$638	\$527	\$539
Beginning reserves (in billions of barrels)	20	20	20	20

In any case, the inelasticity of production with respect to severance tax and price changes suggests that severance tax collections computed as $s = \tau_p(1 - \tau_r)pq - \delta k(w)$ should increase roughly in proportion to changes in the tax rate when $\delta = 0$. As shown in Table 9.3, discounted (at 4 percent) severance tax collections over the 110-year program period total \$159.0 billion for Model B and \$319.2 billion for Model C. Effective severance tax rates for these two models are 0.109 and 0.228, respectively. These figures suggest that the arc elasticity of discounted severance tax collections with respect to a change in the effective tax rate is 0.95 (assuming unchanged royalty rates and oil prices). Model D, which includes the credit ($\delta = 0.22$) for drilling expenses, reflects smaller severance tax collections than Model C.

Table 9.3 indicates that severance tax rate increases result in lower collections of both state and federal corporate income taxes. Because of the deductibility of severance tax payments against these two taxes, discounted state corporate income tax collections fall from \$60.9 billion in Model B to \$49.6 billion in Model C, and discounted federal corporate income tax collections fall from \$230.0 billion in Model B to \$182.5 billion in Model C. Notice that the decline in federal corporate income tax collections is cushioned by declines in depletion allowance deductions (\$119 billion to \$114.9 billion) and in deductions for current and capitalized drilling costs. The value of these two deductions declines because both production and drilling are lower in Model D than in Model C. Also, discounted oil industry profits fall sharply when all taxes are imposed (compare Model A with Models B and C). In any case, the main effects of severance tax rate increases are to redirect (1) oil industry profits to the public sector and (2) tax payments from the federal level to the state level.

Although the specific way in which the model is parameterized may be responsible for the relative insensitivity of production to changes in oil prices and severance tax rates, results shown in Figure 9.1 and Table 9.3 are broadly consistent with U.S. experience over the past half-century. Figure 9.2 shows this by plotting total U.S. proven reserves (in billions of barrels), total U.S. production from proven reserves (in hundred millions of barrels), and the real price of crude oil (in year 2000 dollars).

Proven reserves stood at roughly 30 billion barrels from 1959 to 1970, increased to nearly 40 billion barrels in 1971 with the discovery of oil in Prudhoe Bay, and then declined steadily thereafter to 20.9 billion barrels in 2007. Over this time period, production followed a similar pattern, remaining between 8 percent and 11 percent of reserves in each year; on average, production represented 9.2 percent of reserves with standard error

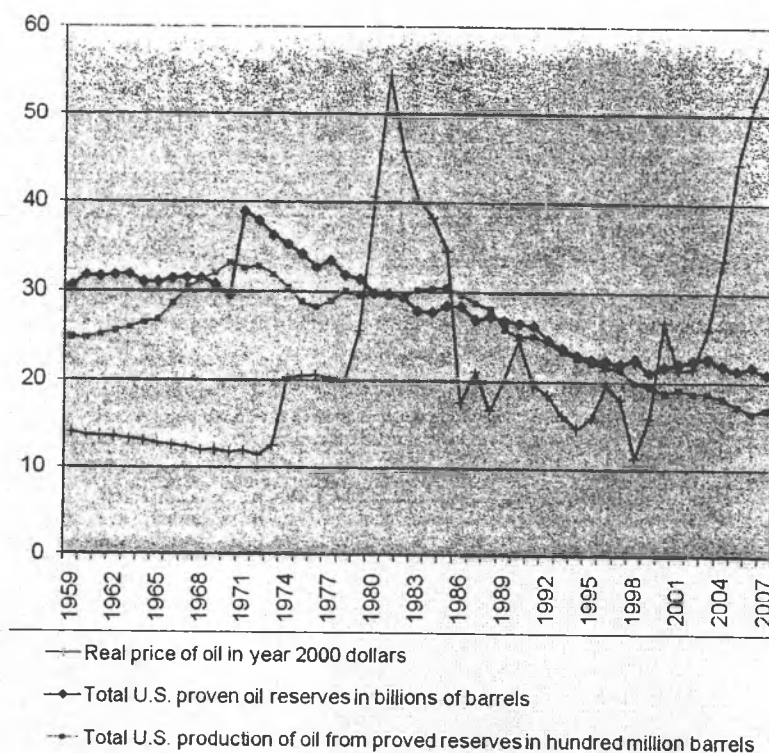


Figure 9.2. U.S. oil production has been insensitive to oil prices over the past 50 years.

of 1.34. Real crude oil prices, on the other hand, exhibited greater variability, but neither the spike in the late 1970s and early 1980s nor the price increase seen in recent years appears to have had much effect on production.

Drilling activity during the 110-year program shows greater percentage differences across the four models (see Figure 9.3 and Table 9.3) than were computed for production.

Model A has the most drilling in each year of the simulation period. Total drilling in Models B and C are lower by 13.3 percent and 20.0 percent, respectively, than in Model A, because the imposition of severance taxes reduces the future payoff from this activity. The effect of the 22 percent drilling expense credit in Model D is to increase drilling above the levels predicted for Model B, but still 13.3 percent below the level predicted for Model A. Total drilling over the 110-year simulation period (net of the starting value of 2 billion feet) is 4.5 billion feet for Model A, 3.9 billion feet for Model B, 3.6 billion feet for Model C, and 3.9 billion feet for Model D.

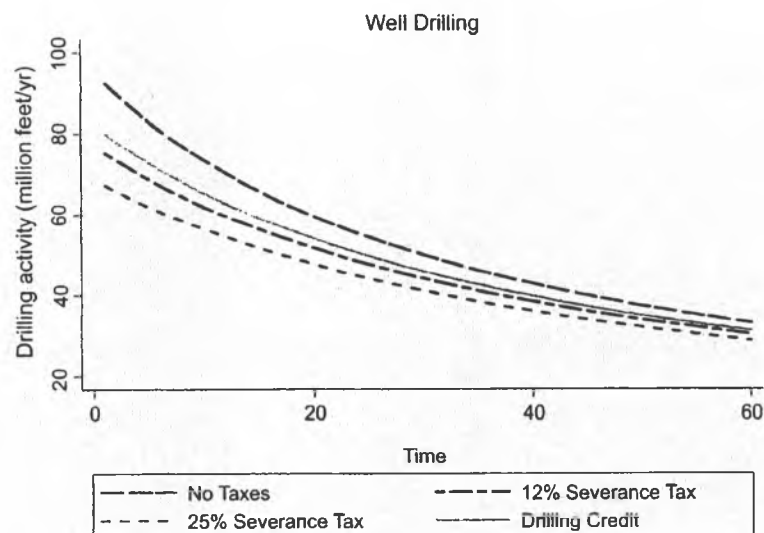


Figure 9.3. Drilling activity is more sensitive to the tax regime.

The figures presented in Table 9.3 imply that the long-run arc elasticity of footage drilled over the 110-year program with respect to the severance tax changes contemplated in Models B and C is -0.07 . The corresponding price elasticity is 0.91 . Thus, in percentage terms, drilling is more responsive to tax and price changes than is production. Figure 9.4 shows that these results are roughly consistent with the observed relationship between drilling footage and real oil prices (defined as in Figure 9.2) in the United States over the past 50 years.

As shown, drilling footage responds positively to changes in the real oil price, and a regression of the natural logarithm of footage drilled on the natural logarithm of the real price of crude oil yields a coefficient of the latter variable of 0.44 (t -statistic = 3.38). This estimate compares favorably with estimates produced by the simulation model.

Another perspective on the results for the time path of drilling and production can be obtained by focusing on the behavior of reserves. In all four models, initial reserves are set to 20 billion barrels. Drilling leads to annual reserve additions, and reserve additions are highest when more drilling is carried out. In consequence, reserve additions tend to be higher for Model A than for either Models B or C. Reserve additions also are higher for Model D than for Model B, again illustrating the effect of the drilling expense

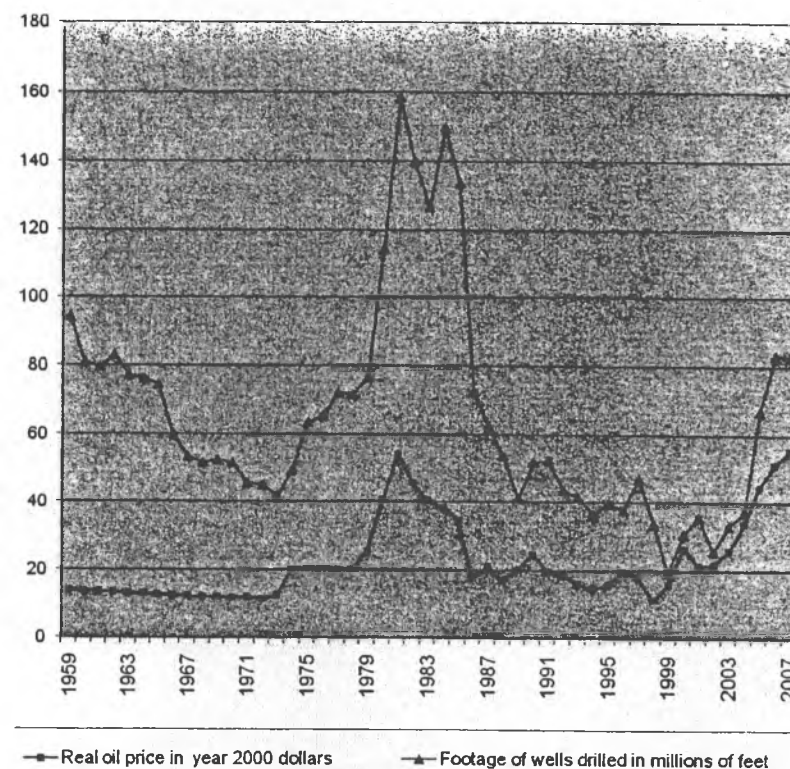


Figure 9.4. Price movements coincide with changes in footage of wells drilled.

subsidy. In all four models, however, annual reserve additions always are exceeded by annual production and thus reflect declining reserves over time. This outcome can be seen in Table 9.3 by comparing beginning reserves with the much smaller corresponding figures for ending reserves.¹² Moreover, this outcome is consistent with the previously discussed trends presented in Figure 9.2, which illustrate that U.S. proven reserves have declined by about 50 percent over the past half-century.

Table 9.3 presents additional information concerning the effect of the 22 percent drilling expense credit subsidy on drilling, production, reserves, and tax collections.¹³ As discussed previously, the credit spurs drilling over

¹² The ending values for reserves reflect high-grading brought about by the severance tax, as discussed in the theoretical literature. For instance, ending reserves in Models B and C are 38 percent and 63 percent higher, respectively, than for Model A.

¹³ Results presented below concerning effects of a drilling expense credit may also inform the current debate about the proposed elimination of the possibility to expense intangible

the life of the program, which adds to the reserve base and raises production (compare Models C and D). Discounted drilling expenditures rise by 29 percent (\$20 billion), but because drilling expenditures rise at an increasing rate with footage drilled (see equation (9.10)), footage drilled rises by a smaller percentage (8 percent or 0.3 billion feet). The 0.6 billion barrel increase in production associated with the credit approximately offsets the effect on production of increasing the severance tax rate from 12 percent to 25 percent (compare Models B and D). Application of the credit results in 14 percent fewer remaining reserves at the end of the program (compare Models C and D) and roughly offsets the effect on ending reserves that results from the severance tax increase in Model C as compared with Model D.

The incremental production resulting from the drilling expense credit results in an increased present value of severance tax collections (gross of the credit) in Model D (\$326.9 billion) as compared with Model C (\$319.2 billion). Once the present value of drilling expense credits are subtracted, however, the net-of-credit present value of severance tax collections in Model D (\$307.5 billion) ends up lower than in Model C by 3.7 percent, yet they are 93.4 percent higher in Model D than in Model B. Comparing Models D and C, \$1.2 billion in lost severance tax revenue is regained through increased state corporate income tax collections; however, \$5.9 billion in lost severance tax revenue is transferred to the federal government in the form of higher federal corporate income tax payments. In any case, the drilling expense credit results in a net loss in discounted state tax revenue of \$10.5 billion. It costs about \$17.50 in lost discounted state tax revenue (both severance tax and state corporate income tax) to produce an additional barrel of oil and about \$35.00 of lost discounted state tax revenue to drill an additional foot. Additionally, each dollar of discounted state tax revenue lost because of the credit is associated with a \$1.90 increase in drilling expenditures.

This outcome raises a question as to whether other public policy instruments, such as support for research to lower drilling costs or to increase finding rates, might spur drilling at lower cost to the state. Nonetheless, if a state's objective in granting the drilling expense credit is to gain support for increasing the severance tax rate from 12 percent to 25 percent, it is a relatively inexpensive concession. On the other hand, a state that expects the drilling expense credit to more than pay for itself through severance

drilling costs in computing federal corporate income tax liabilities. Both types of policies operate through α_D while leaving the other two tax parameters unchanged.

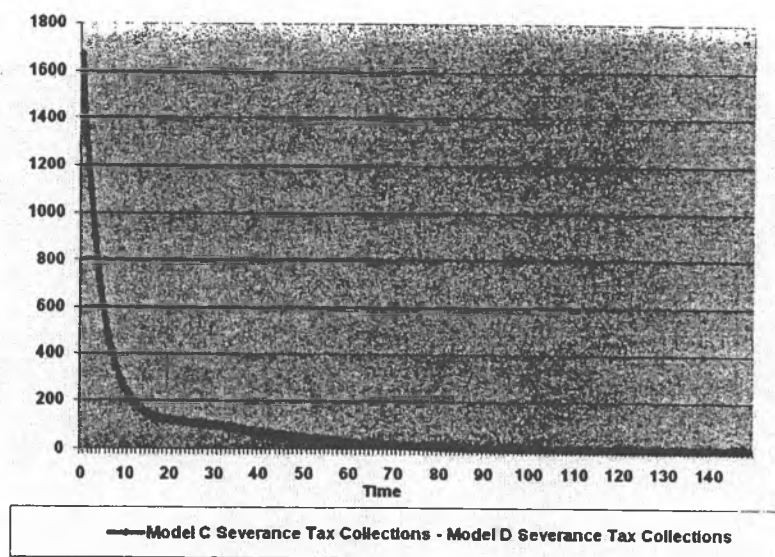


Figure 9.5. Discounted severance tax losses from the drilling expense credit accumulate over time.

tax collections will be disappointed because it simply generates too little incremental oil production. In fact, the drilling expense credit is not only cost-ineffective when evaluated over the entire program, it is cost-ineffective in each program year, as shown in Figure 9.5.

As can be seen from Table 9.2, the credit results in a 17 percent increase in drilling in year 1 (compare Models C and D), but no additional production and thus no additional revenue. Model D production begins to reflect the additional drilling in year 2 and exceeds that for Model C until year 48. During these years, severance tax losses in Model D compared to Model C are smaller than the value of the credit. As indicated, beginning in year 49, production in Model C is larger than that for Model D. Thus, in years 49 to 110, the loss in severance tax revenue in Model D compared to Model C exceeds the value of the credit.

A possible concern about these calculations is that they pertain to a model that is parameterized using U.S. oilfield data. In particular, one conjecture might be that a drilling credit might be financially more attractive in an area that has been less extensively explored, so that the marginal product of drilling in identifying new reserves would be higher. To check this idea, the simulation model was recalibrated by assuming that cumulative drilled footage prior to the start of the program was 500 million feet, rather than

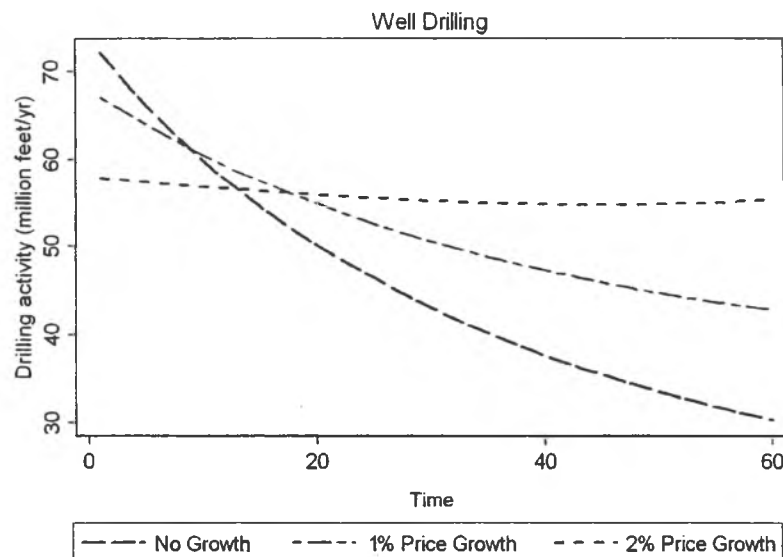


Figure 9.6. Oil drilling tilts to the future with exogenous growth in oil prices.

2 billion feet. This alteration roughly doubles the marginal product of drilling in identifying new reserves, which in turn stimulates drilling, reserve additions, and production. Therefore, Model C discounted severance tax collections are higher than those shown in Table 9.3. Model D discounted severance tax collections also are higher than in Table 9.3, but still lower than the comparable value for Model C. Thus, in both absolute and percentage terms, severance tax losses from the drilling expense credit are larger when cumulative footage drilled totals 500 million feet as compared with 2 billion feet.

It would also be of interest to construct a simulation using the actual path of oil prices over the last several decades. This price, however, exhibits sharp increases and decreases over time (see Figure 9.2), causing the simulation algorithm to break down. As a second choice, we performed a set of sensitivity analyses to reflect a forecast that oil prices will rise over time, at two exogenously given rates. Of course, with perfect foresight, prices cannot go up faster than the rate of discount, because then oil production will be postponed to the future. We thus assume exogenous growth rates in oil prices of 1 percent and 2 percent. As shown in Figure 9.6, drilling activity flattens out with a 2 percent growth in prices.

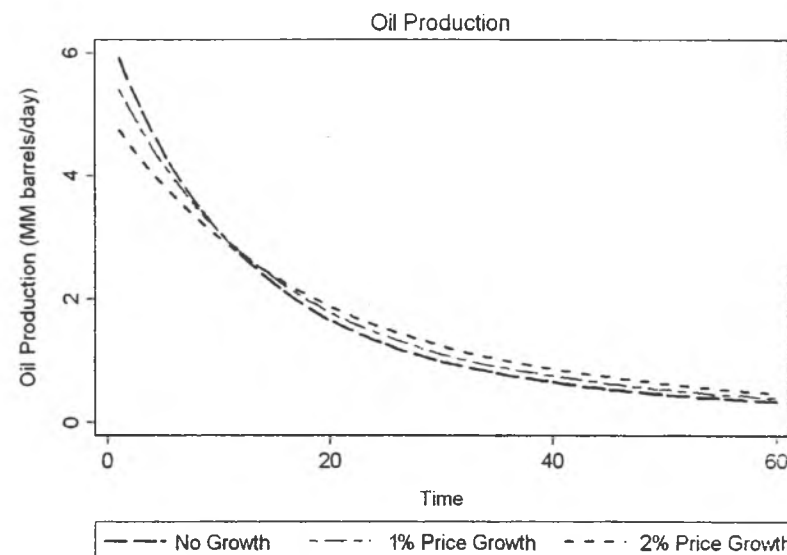


Figure 9.7. Oil production does not change appreciably with growth in oil prices.

However, oil production is relatively insensitive to oil price growth, as shown in Figure 9.7. This is because even though drilling activity shifts out to the future with an increase in prices, the decline in returns from cumulative drilling keeps production from leveling out in time. Production continues to fall, as in the case with constant prices. Figure 9.8 shows the change in reserve additions in the price growth scenario.

9.7 Concluding Remarks

This chapter described tax policies pursued by U.S. states that impact the oil industry. Three types of taxes are discussed: (1) the severance or production tax, (2) the property tax, and (3) the corporate income tax. The severance tax then is further analyzed in light of its widespread use in energy-producing states and its potential to generate revenues to support public services. The analysis is carried out using an adaptation of a conceptual model (Pindyck 1978) of exploration/development and production of exhaustible resources in which oil prices are taken as exogenous. This perspective is a useful simplification for an analysis of state taxes because no state produces enough oil to appreciably affect the world price. Simulations obtained from calibrating the model suggest that oil production volumes will be quite insensitive to

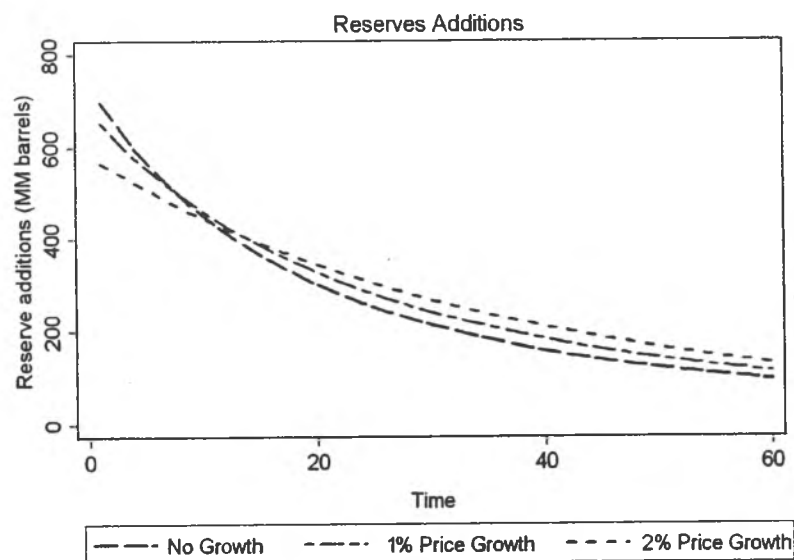


Figure 9.8. Reserve additions change only marginally with growth in oil prices.

price and severance tax rate changes. Thus, an increase in the severance tax rate is seen to generate proportionally more severance tax revenue, as its main effect is to redirect economic rents earned in the oil industry towards the public sector. An implication of this result turns out to be that the proposed elimination of the percentage depletion allowance, available to nonintegrated independent oil producers, may have much the same effect on production as a severance tax increase, although changes in the two types of tax measures may have quite different effects on the distribution of tax revenue between the state and federal levels of government.

Simulations based on the U.S. experience demonstrate that the credit for drilling expenses does turn out to increase drilling as intended. However, if the credit is applied in the United States, particularly in areas where a great deal of drilling has already occurred, its contribution to identifying new reserves may be rather limited. In other words, much of the continental United States has been extensively explored, so the chances of large oil discoveries probably are small. Simulations of the model show that the drilling expense credit does not generate enough incremental severance tax revenue to pay for itself. Additional work needs to be carried out to see whether alternative public policies to stimulate exploration and development might be more cost-effective as well as the extent to which the results presented continue to hold when the model is parameterized differently.

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11.

**"Effectiveness
of Severance Tax
Incentives in
the U.S. Oil
Industry"**



Effectiveness of Severance Tax Incentives in the U.S. Oil Industry

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Abstract

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. In general, results show that severance tax incentives (in the form of tax rate reductions) substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

Keywords: state taxation, nonrenewable resources

JEL Code: H71, Q32

1. Introduction

For roughly twenty years, major oil and gas producing states have granted severance tax exemptions, reductions, incentives, and credits to oil and gas producers for the purpose of stimulating exploration, field development, production, and job creation.¹ For example, to date 2000, Alaska, Kansas, and Louisiana have offered 13 such incentive programs, Texas has granted 12, Oklahoma 10, New Mexico 8, and Wyoming 8 (Interstate Oil and Gas Compact Commission, 2001). Incentive programs, generally, involve across the board cuts in nominal severance tax rates levied or discounts against existing severance tax liabilities for special situations faced by producers. The inherent tradeoff state governments must consider when offering incentives involves the potential loss of tax revenue for purported gains in exploration and production activity. A key question then arises: Are severance tax incentives effective in this regard? Surprisingly, very little empirical evidence exists regarding this question despite the heavy reliance on taxation of oil, gas, and/or coal production in many states to fund public goods.

This paper develops a dynamic empirical framework that can be used to test the effectiveness of state-level severance tax incentives in the U.S. oil industry. The framework embeds U.S. state-level panel data estimates into Pindyck's (1978) widely received theoretical model of exhaustible resource supply and can be applied to any of 20 states that produce significant

quantities of oil. The model allows for interactions between taxes levied by different levels of government and for the first time addresses potential interstate differences in exploration costs, extraction costs, and reserve additions. As shown, costs, reserve additions, and tax structures vary considerably across states. Thus, this adapted model is arguably superior to and more comprehensive than previous efforts to develop general econometric and/or simulation models of taxation and natural resource exploration and production. Specifically, Deacon et al. (1990) and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be entirely consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes and estimates of the shadow price of oil in the ground are not always positive. Favero (1992) adds taxes to Pesaran's analysis, but again, estimates of the shadow price of oil in the ground are sometimes negative, suggesting that the model overstates the impact of taxation on profit. The Pindyck based simulation studies conducted by Yücel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production but do not consider interactions between tax bases claimed by different levels of government, as well as possible interstate differences in exploration costs, extraction costs, and reserve additions. Also, these studies are aimed mainly at assessing the generality of theoretical results obtained in more limited settings rather than analyzing possible outcomes of changes in state tax policies.

Use of the modeling framework developed here is illustrated by simulating effects of reductions in *existing* state severance tax rates. Thus, results presented have the advantage of showing potential effects of specific state tax policy changes. Examining optimal tax regimes is beyond the scope of this analysis. In general, results show that severance tax rate cuts substantially reduce state tax revenue collected, but yield moderate to little change in oil drilling and production activity. This outcome suggests that states should be wary of arguments asserting that large swings in oil field activity can be obtained from changes in severance tax rates.

The remainder of the paper is divided into four sections. Section 2 presents the theoretical model used in the study. Section 3 presents empirical estimates of the model's parameters. Key estimates are obtained using panel data from the 20 most important oil-producing states over the period 1970–2000. Section 4 presents simulation results showing how oil exploration, reserves and production in Wyoming vary in response to severance tax reductions. Although the model developed can be applied to any of 20 states that produce significant quantities of oil, Wyoming is singled out because the estimates developed are likely to be at least broadly representative of what would be obtained for other states. Moreover, focusing on Wyoming highlights the state's heavy reliance on energy production taxes to fund public services. Implications and conclusions of this analysis are drawn out in Section 5.

2. Conceptual Framework and Model

The analysis presented in this paper extends Pindyck's (1978) model of nonrenewable resource development to incorporate key aspects of federal, state and local taxes facing the U.S. oil industry. Because the theoretical model is familiar, discussion later in this

section is kept to a minimum. Perfectly competitive producers are assumed to maximize the discounted present value of future operating profits from the sale of resources. The firm's problem is to take known future output prices and taxes as given and then choose optimal time paths for exploration and production. This assumption parallels the basic tax competition models, reviewed by Wilson (1999), where governments commit to a tax regime and then perfectly competitive firms react treating the structure as exogenous.² Whereas the studies reviewed by Wilson model firms that are to some extent geographically mobile, firms extracting nonrenewable resources are tied to an immobile reserve base that represents the key component of their capital stock. In consequence, extractive firms view time, rather than space, as the most important dimension over which to substitute in response to changes in tax policy. Substitutions over time, of course, alter relative rates of exploration and production occurring at different locations. Yet, timing of activities is the most important aspect of the extractive firm's problem and information about location choice can be recovered as a by-product simply by comparing rates of development for particular reserves. A single firm is used to represent the industry, so the common pool problem and well spacing regulations are ignored (McDonald, 1994). For simplicity and because of data constraints discussed in the next section, exploration is defined to include resource development, although the two activities clearly are not the same (Adelman, 1990). The aim of exploration is to add to the reserve base, which in the model represents a form of immobile capital.

Institutional features of taxation facing oil producers are complex, however, incorporating these aspects into the model is not difficult conceptually and distinctly separates it from previous efforts mentioned in the introduction. Tax structures vary considerably among states and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of 2000 U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy severance taxes against the value of output. Severance taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Hence, effective rather than nominal rates are incorporated in the model developed below. Within states, counties apply their own mill levies to compute property taxes on above-ground and down-hole equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are not treated in the model below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent

incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is not treated here.

The firm's maximization problem now becomes

$$\max_{q, w} \Omega = \int_0^{\infty} [qp - C(q, R) - D(w) - \gamma R] e^{-rt} dt \quad (1)$$

subject to

$$\dot{R} = \dot{x} - q \quad (2)$$

$$\dot{x} = f(w, x) \quad (3)$$

$$q \geq 0, \quad w \geq 0, \quad R \geq 0, \quad x \geq 0 \quad (4)$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(q, R)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(w, x)$ denotes the production function for gross reserve additions ($\dot{x}$) which is assumed to depend on current exploratory effort (w) and cumulative discoveries (x), and $\dot{R}$ denotes reserve additions net of production (q).³ In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a constant comprised of federal, state, and local effective tax rates such that $0 < \alpha_p < 1$. Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = \alpha_D D^*(w)$, where α_c and α_D also are constants generated from effective tax rates and lie on the unit interval. A more complete discussion of the tax policy parameters follows below in Section 3.3.

The Hamiltonian for this problem is

$$H = qpe^{-rt} - C(q, R)e^{-rt} - D(w)e^{-rt} - \gamma Re^{-rt} + \lambda_1[f(w, x) - q] + \lambda_2[f(w, x)]. \quad (5)$$

Differentiating H with respect to R , q , x , and w yields the maximum principle conditions

$$\dot{\lambda}_1 = (C_R + \gamma)e^{-rt} \quad (6)$$

$$pe^{-rt} - C_q e^{-rt} - \lambda_1 = 0 \quad (7)$$

$$\dot{\lambda}_2 = -f_x(\lambda_1 + \lambda_2) \quad (8)$$

$$-D_w e^{-rt} + f_w(\lambda_1 + \lambda_2) = 0. \quad (9)$$

From equation (7), operators will produce if the discounted net-of-tax price exceeds discounted extraction costs. A severance tax decrease will increase the net-of-tax price which could affect the production decision. In equations (6)–(9), λ_1 is the discounted shadow price of the reserve state, λ_2 is the discounted shadow price of cumulative reserve additions, and letter subscripts represent partial derivatives. The shadow price of cumulative reserve additions, λ_2 , is expected to be negative (and small relative to λ_1) for oil because current reserve

discoveries will increase the amount of exploration needed in the future. From equations (8) and (9), the term $(\lambda_1 + \lambda_2)$ equals the discounted value of the marginal cost of adding another unit of reserves by exploration $[D_w/f_w]e^{-rt}$. Because $0 < \alpha_D < 1$, this net marginal cost is lower than in the pretax case.

The evolution of q is obtained by differentiating equation (7) with respect to time and setting the result equal to equation (6) to eliminate $\dot{\lambda}_1$. This yields

$$\dot{q} = \frac{-r(p - C_q) + \dot{p} - C_{qR}\dot{R} - (C_R + \gamma)}{C_{qq}}. \quad (10)$$

The optimal time path of w , can be determined using equation (7) and equation (9) to solve for λ_2 , differentiating with respect to time to obtain an expression for $\dot{\lambda}_2$, equating the result to equation (8) and rearranging terms:⁴

$$\dot{w} = \frac{D_w[(f_{wx}/f_w) \cdot f - f_x + r] + (C_R + \gamma)f_w}{[-D_w(f_{ww}/f_w)]} \quad (11)$$

Equation (11) shows that the trajectory of exploratory effort is determined by a tradeoff between the cost of finding new reserves and the extraction cost savings this new level of reserves yields. As specified in this model, a severance tax incentive (rate decrease) could increase incentives to explore and enhance reserves due to the subsequent increase in the net-of-tax price. This effect is discussed in more detail in Section 4. The numerator of equation (10) emphasizes the role reserves play in the optimal extraction path. If reserves rise, marginal extraction costs fall, thus increasing production. While general suppositions such as these can be drawn analytically, the complexity of the dynamic process just described may be best examined with simulation as developed below.

Boundary conditions can be established by first assuming that $D_w/f_w = 0$ when $w = 0$ (see Pindyck, 1978, pp. 846–847). In this situation, when production ceases at some terminal time T , exploration ceases at the same time because it is of no further value. Also, $\lambda_2(T) = 0$ as long as there are no terminal costs associated with cumulative discoveries. In consequence, from equation (9), $\lambda_1(T) = 0$ implies that operating profit on the last unit of reserves extracted is zero, $p = C_q$. An alternative terminal state centers on the case where $D_w/f_w = \Phi > 0$, when $w = 0$. In this situation, production will continue after exploratory effort ceases. Let $T_1 < T$ denote the time when $w = 0$. If exploratory effort is zero, $f_x = 0$, hence $\dot{\lambda}_2(T_1) = 0$ and $\lambda_2(T_1) = 0$. From (7) and (9), $p - C_q = \lambda_1(T_1)e^{rt} = \Phi = D_w/f_w$ which indicates that exploration will stop just as $p - C_q$ approaches marginal discovery cost, Φ . These two alternative terminal conditions are discussed in the next section as well as in connection with the simulations presented in Section 4.

3. Estimation

As shown in equations (10) and (11), the evolutions of w and q are nonlinear functions of both the levels of these variables and the previously defined tax parameters. Estimating these equations directly poses certain econometric issues (see Pesaran, 1990) and it is unclear how information from the transversality conditions would be incorporated. In consequence, rather than attempt to obtain econometric estimates of these two equations directly, equations

for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax policy parameters α_p , α_c , α_D , and γ (see Yücel, 1989; Deacon, 1993 for similar treatments). Effects of severance tax changes then are obtained by simulation. State-specific estimates of equations for D^* and f are treated together in Section 3.1 because they are used to compute the marginal cost of reserve additions (D_w^*/f_w) which is a crucial function of the model described above. The equation for C^* is treated in Section 3.2 and the tax parameters are derived in Section 3.3. Key interstate differences regarding all estimates are highlighted throughout the discussion below.

3.1. Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D_w^*/f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are modeled in equation (12) as proportional to drilling effort.

$$D^*(w) = \phi w e^u \quad (12)$$

This approach ensures that the objective function (see equation (1)) represents a perfectly competitive firm ($D_{ww} = 0$). In equation (12), ϕ is the parameter to be estimated, and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2 . Data by state and over time on labor, capital, and other primary inputs to drilling are unavailable, so the annual number of wells drilled in a state is used as a measure of drilling effort (w). Data on footage drilled also could be used as a measure of w (see Deacon, 1993). However, in the data set applied (see below) the number of wells drilled is positively correlated with total footage drilled (Pearson correlation = .98). Also, total drilling cost is approximately proportional to both footage and the number of wells, so to some extent the two variables measure the same thing. As discussed in Section 2, cumulative reserve discovery (x) appears as an argument in the production function for new reserves (see equation (13) below). A proxy for x can be constructed from available data (American Petroleum Institute, 1971) on the total number of wells drilled by state since 1859 (when the first oil well was drilled in Pennsylvania), whereas corresponding data on total footage drilled since that date are not available. Thus, use of number of wells as a measure of drilling effort simplifies the simulations presented in Section 4 and eliminates the need for arbitrary assumptions about historical average depth per well.

The production function for reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta \cdot x} e^v \quad (13)$$

where A , ρ , and β are parameters to be estimated and the multiplicative disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . The functional form selected for f is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted and estimated by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate. As previously discussed, data on cumulative reserve discoveries of oil are unavailable, so the cumulative number of wells drilled by state was used as a proxy.

As in the drilling cost function, the annual number of wells drilled is used as a measure of w .

Drilling cost and reserve production functions are estimated using annual data from 20 U.S. states for which complete information on wells drilled, drilling costs, reserve additions, and cumulative drilling could be assembled for the period 1970–2000.⁵ Regarding costs, operators report the total cost (both tangible and intangible) of each well completed (including dry holes) via the Joint Association Survey on Drilling Costs.⁶ Oil reserve additions are comprised of extensions, new field discoveries and new reservoir discoveries in old fields as defined by the U.S. Department of Energy, Energy Information Administration (DOE/EIA). The 20 states included in the data set accounted for 98.5% of the total U.S. oil production over 1970–2000.

Data sources, definitions, and sample means of variables used in the analysis are presented in Table 1. All nominal costs are converted to year 2000 dollars using the GDP deflator. Equations (12) and (13) were estimated in natural logarithms. An instrument for the natural logarithm of *WELLS* was used in equation (13) because w is an endogenous variable in the model presented in Section 2 and a Durbin-Wu-Hausman test (see Davidson and MacKinnon, 1993, pp. 389–393) rejected the exogeneity of w at the 5% level. An instrument for w was obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table 2. Time-specific effects tested insignificant at conventional levels. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE***CWELLS* were included to account for non-linearities expected in light of relationships in the model. All estimated coefficients are significantly different from zero at conventional levels. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of $\ln(WELLS)$ and the corresponding predicted values, $\ln(PREDWELLS)$, is 0.96.

Estimates of the drilling cost equation (12) are obtained by regressing the natural log of drilling costs minus the natural log of wells on dummy variables for states and years. This two-way fixed effects approach is a simple way to control for heterogeneity across states and over time. Examples of state-specific effects include geologic conditions, geographic remoteness of on-shore oil and gas resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. For this equation, each state-specific effect for a given year, conveniently, becomes the state-specific estimate of ϕ .

Estimates of equation (13) are obtained in a one-way fixed effects framework that yields common estimates of the slope coefficients across states and corrects for first-order serial correlation.⁷ The one-way fixed effects estimation with correction for serial correlation is used for four interrelated reasons. First, this approach is a simple way to control for, yet avoid enumerating, unique aspects of states that affect reserve additions, but do not change over time. Second, time-specific effects are not jointly significant at conventional levels, making estimation in a two-way fixed effects framework unnecessary. Third, the random-effects specification, in which state-specific effects are treated as error components, is rejected by a Hausman (1978) test at the 5% level of significance. Moreover, conditional estimates of

Table 1. Variable definitions, data sources, and sample means.

Variable	Definition	Source	Sample mean
<i>TRCOST</i>	Total drilling costs in millions of 2000 dollars, for oil wells by state and year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	332
<i>WELLS</i>	Total oil wells drilled in a state by year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	741
<i>CWELLS</i>	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute. <i>Petroleum Facts & Figures</i> (1971 ed.)	95492
<i>TRCWELL</i>	Total drilling cost per well drilled, by state and year, in millions of 2000 dollars.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	0.723
<i>FTWELL</i>	Total footage per well drilled, by state and year.	American Petroleum Institute. <i>Joint Association Survey on Drilling Costs</i> . Annual.	5666
<i>PRICE</i>	Average wellhead price of oil per barrel, by state and year, in 2000 dollars.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	24.56
<i>ADDED RESERVES</i>	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	U.S. Energy Administration. <i>U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves</i> . Annual.	31.4
<i>RESERVES</i>	Proved reserves by state and year in millions of barrels.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	1320.5
<i>PROD</i>	Production by state and year in millions of barrels.	American Petroleum Institute. <i>Basic Petroleum Data Book</i> . Feb. and Aug. Annually.	126.4
<i>PRICE2</i>	Average real price squared.	—	757
<i>CWELLS2</i>	Cumulative total wells squared.	—	3.4E+10
<i>PRICE* CWELLS</i>	Interaction of real price and cumulative total wells.	—	2.4E+6

the effects on reserve additions obtained from fixed-effects are thought to be of greater interest than corresponding unconditional estimates obtained using random effects. Fourth, the null hypothesis of no serial correlation is rejected at the 5% level, hence, the equation was re-estimated with correction for first-order serial correlation.

Table 3 reports estimates of the drilling cost equation for 8 major producing states. The 2000 state-specific estimates of ϕ have been corrected for the fact that the equation was estimated in logarithmic form (see Greene, 1997, p. 279). As shown, R^2 is 0.93 with state- and time-specific effects jointly significant under the appropriate F-test. State-specific estimates of ϕ test different from each other, except for Texas and Oklahoma, at the 5% level. Results suggest that total drilling costs increase with w and that constant marginal drilling

Table 2. One-way fixed effects construction of instrument for $LN(WELLS)$.

Explanatory variable	Coefficient (t-statistic)
<i>PRICE</i>	0.062 (6.58)
<i>PRICE2</i>	-0.32E-3 (-2.34)
<i>CWELLS</i>	-0.33E-4 (-6.76)
<i>CWELLS2</i>	0.22E-10 (5.46)
<i>PRICE * CWELLS</i>	0.72E-8 (1.82)
Summary statistics	
NT	620
R^2	0.86
$F(19,596)^a$	49.55
$F(30,565)^b$	1.18
Hausman ^c	45.20

^aTest statistic for joint significance of state-specific effects.^bTest statistic for joint significance of time-effects after removing state-specific effects.^cStatistic for testing consistency of corresponding random effects estimates.

costs (D_w^*) differ substantially across the 8 states shown. Estimates of the reserve addition equation are shown in Tables 4 and 5. The coefficient of $LN(PREDWELLS)$ is 0.56 and this estimate is significantly different from one and zero at conventional levels. The value of R^2 is 0.63 and the state-specific effects are jointly significant under the appropriate F-test. Also, the negative coefficient of $CWELLS$, though insignificant at conventional levels, suggests that reserve additions decline with the passage of time as new reserves become more difficult to identify. Table 5 shows the corrected state-specific intercept terms (A) for 8 major producing states. Results suggest that the marginal product of drilling (f_w) decreases with wells drilled and this marginal product would vary between states even if the number of wells drilled were the same in each.

Estimates of the two equations combined suggest that marginal cost of reserve additions (D_w^*/f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 6 shows how pre-tax values of D_w^* , f_w , and D_w^*/f_w differ by state for 8 of the major producing states, assuming that the 2000 level of wells are drilled in each. Estimates of drilling cost per well (D_w^*) range from \$132,907 in Kansas, where wells tend to be shallow, to \$3,881,600 in Alaska, where the drilling experience is very different as compared to the lower 48 states. Marginal reserve additions from drilling (f_w) range from 11,051 barrels per well

Table 3. Two-way fixed effects, instrumental variable estimates of the drilling cost function (Corrected 2000 estimates of ϕ for 8 major producing states^a).

State	Corrected fixed effect (<i>t</i> -statistic)
Alaska	3.881 (16.25)
California	0.277 (15.28)
Kansas	0.133 (24.05)
Louisiana	1.323 (3.38)
New Mexico	0.493 (8.41)
Oklahoma	0.357 (12.26)
Texas	0.352 (12.44)
Wyoming	0.601 (6.04)
Summary statistics	
NT	620
R ²	0.93
F(49,570) ^b	149.5

^aSee Greene (1997, p. 279) for specific details on intercept bias adjustment. 2000 time-effect added.

^bTest of joint significance of state- and time-specific effects.

in Kansas to 177,067 barrels per well in Alaska. Thus, while drilling a well in Alaska is markedly more expensive than in Kansas, Alaska experiences a greater payoff from these more costly exploration and development efforts. In fact, estimates of the marginal cost of reserve additions, D_w^*/f_w , reflect somewhat less variation across states than do estimates of either D_w^* or f_w , ranging from a low of \$11.24 per barrel in Louisiana to a high of \$21.92 in Alaska. Although relatively little variation in D_w^*/f_w would be expected when operators are familiar with costs and payoffs from drilling in alternative locations, values of the marginal cost of reserve additions are not expected to be equal across states. For example, aside from random factors introduced in estimation, variation in D_w^*/f_w between states could be due to differences in oil quality, transportation costs, as well as other factors that can cause wellhead prices of oil to differ across states

3.2. Extraction Costs

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA for the period

Table 4. One-way fixed effects, instrumental variable estimates of the reserve additions function.

Explanatory variable	Coefficient (t-statistic)
<i>LN(PREDWELLS)</i>	0.56 (11.09)
<i>CWELLS</i>	-0.3E-5 (-1.26)
Summary statistics	
NT	620
R ²	0.63
F(19,579) ^a	22.2
F(30,568) ^b	1.12
RHO	0.394
Hausman ^c	15.1

^aStatistic for testing joint significance of state-specific effects.

^bStatistic for testing joint significance of time-specific effects after removing state effects.

^cStatistic for testing consistency of corresponding random effects estimates.

Table 5. One-way fixed effects, instrumental variable estimates of the reserve additions function (Corrected estimates of *A* for 8 major producing states^a).

State	Corrected fixed effect (t-statistic)
Alaska	1.57 (1.64)
California	0.78 (2.01)
Kansas	0.31 (1.17)
Louisiana	2.49 (1.82)
New Mexico	0.57 (1.68)
Oklahoma	0.62 (1.94)
Texas	0.52 (2.11)
Wyoming	0.78 (2.03)

^aSee Greene (1997, p. 279) for specific details on intercept bias adjustment.

Table 6. Pre-tax marginal drilling cost, marginal product of drilling, marginal cost of reserve additions for 8 major producing states^a.

State	D_w^* (in \$)	f_w (in bbls)	D_w^*/f_w
Alaska	3,881,600	177,067	21.92
California	277,119	14,717	18.83
Kansas	132,907	11,051	12.03
Louisiana	1,323,014	117,753	11.24
New Mexico	492,620	27,123	18.16
Oklahoma	356,754	23,477	15.20
Texas	351,654	24,219	14.52
Wyoming	600,911	39,238	15.31

^aEvaluated at each state's actual 2000 wells drilled. State-specific cumulative wells total is set to actual 2000 values.

1970–2000. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^\varepsilon R^{1-\varepsilon}, \quad (14)$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant that drives the production cost modeled to an average level of *lifting costs* representative of the 2000 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Deacon, 1993 for specific calibration methods). Table 7

Table 7. Non-reserve production input share μ , and pre-tax marginal extraction cost for major producing states.

State	μ	C_q^a
California	0.27	7.12
Kansas	0.17	4.99
Louisiana	0.21	9.11
New Mexico	0.31	6.87
Oklahoma	0.26	6.89
Texas	0.32	7.01
Wyoming	0.34	6.93

^aCalculated at 2000 levels for production and reserves, in year 2000 dollars. The EIA does not provide data for Alaska.

shows the pre-tax marginal extraction costs (C_q^*) and the non-reserve input shares (μ) for 7 major producing states. The DOE/EIA does not estimate lifting costs for Alaska. As shown, real marginal extraction costs range from a low of \$4.99 per barrel in Kansas to a high of \$9.11 per barrel in Louisiana. The Cobb-Douglas form for extraction costs insures that these costs will rise without limit as reserves approach zero. This condition implies that a positive level of reserves will remain at any terminal time, denoted T_1 . Likewise, the functional form invokes a strictly positive level of production given any positive level of reserves. Thus, simulations reported in Section 4 are based on the second of the two alternative boundary conditions discussed in Section 2. This condition implies that production continues after incentives for further exploration vanish and that the terminal date for maximizing discounted operating profits must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3.3. Tax Policy Parameters

For most states in most years, γ and α_j ($j = p, C, D$) can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating the following equations:

$$\gamma = \{(1 - \tau_{us})(1 - \tau_s)\tau_R\} \quad (15)$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \quad (16)$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \quad (17)$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \quad (18)$$

The derivation of equations (15)–(18) can be found in Appendix A. In (15)–(18), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. The parameter η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct (tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well.

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in

Section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) and Deacon et al. (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (15)–(18) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state. Royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1999–2000) for the oil and gas sector show that federal corporate taxes paid averaged about 11% of *net operating* income in 2000. The ratio of the federal effective to marginal rate was also applied to each state's top marginal corporate income tax rate to obtain an effective estimate. The current nominal percentage depletion rate is 15% and it applies to each state's percentage of non-integrated producers. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see U.S. Department of Commerce, Bureau of the Census, 2000; Deacon, 1993). The ratio of production to reserves (q/R) varies across states but the industry expense share (42%) applies to all states.

4. Simulation Results

The model presented in Section 2 can be simulated for any of the 20 oil-producing states to obtain responses of exploration and production to reductions in severance taxes. The discussion below focuses mainly on severance tax rate reductions in just one state, Wyoming, for four reasons. First, this approach substantially reduces the amount of institutional detail that must be presented. Second, despite the large interstate differences in costs, reserve additions, and tax structures shown above, changes in severance taxes turn out to have quite similar comparative effects in each of the major oil producing states. Therefore, estimates for Wyoming are likely to be broadly representative of what would be obtained for other states. Third, simulation results reported are based on the assumption that severance tax reductions in one state do not affect the wellhead price of oil seen by operators in other states. This assumption is warranted in view of the fact that oil prices are determined in a world market. Also, as shown below, tax rate cuts considered appear to lead to comparatively small changes in output, so cross border effects are unlikely to be important in any case. Finally, taxation of oil extraction is a long-standing, contentious public policy issue in Wyoming partly because of heavy reliance on energy production taxes to fund public services.

Simulations for Wyoming were performed using the estimates of equations (12) and (13), the calibrated production cost parameters ($\varepsilon = 2.93$, $\kappa = 150$) of equation (14), and the tax parameters ($\alpha_p = 0.72$, $\alpha_c = 0.89$, $\alpha_D = 0.75$, $\gamma = 0$) as derived in Appendix A. As shown, severance tax changes will affect the price tax parameter, α_p . The discount rate, r , was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at \$25.00 per barrel each year reflecting the real sample mean for all 20 states. Other price trajectories (rising or falling) were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled are fixed to year-end 2000 levels at 561 million barrels and 39,993 wells, respectively. To obtain numerical solutions for the time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in production and exploratory effort (equations (10) and (11) and for the state variable evolution equations (2) and (3)). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is solved recursively by iterating over the initial values of the control variables, q and w , until transversality conditions are satisfied. Under these base case conditions, exploratory effort approaches zero after approximately 40 years, thus the terminal time (T_1) is set to 40 periods. The Solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, wells drilled, production, and reserves for Wyoming from 1970–2000. In this figure, the vertical axis shows wellhead price (dotted line) in year 2000 dollars $\times 10$, wells drilled (dashed line) in

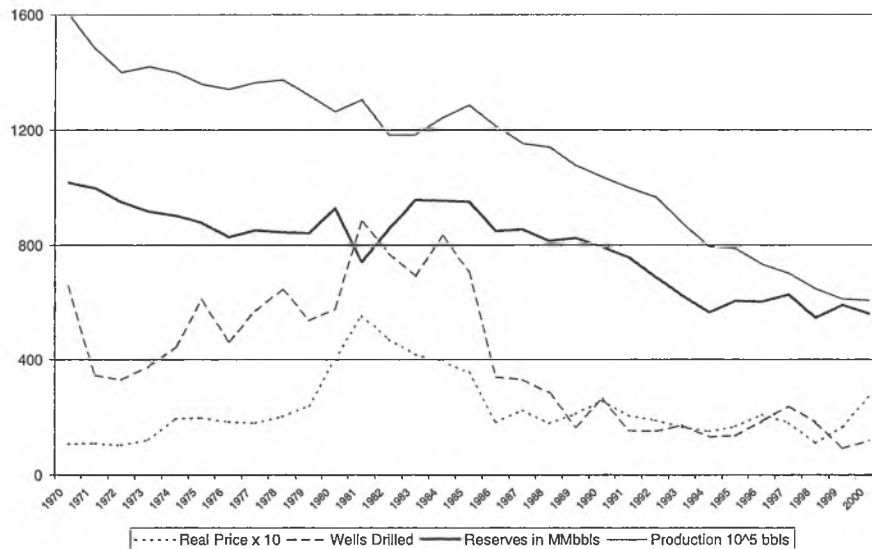


Figure 1. Wyoming oil 1970–2000.

total wells, production (solid line) in $\text{bbls} \times 10^5$, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Oil wells drilled increased markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased roughly 3 fold. As shown, the increased drilling effort of the early to mid 1980s failed to replenish the depleting oil reserves in the state.

As depicted in Figure 1, the low real prices for oil in the 1990's provided the oil industry incentive to lobby state legislatures for tax breaks intended to stimulate exploration and production. In 1999, both Wyoming and Oklahoma enacted oil producer recovery acts which lowered state level nominal severance taxes by approximately 25–35% on all oil production, provided that oil prices remain below a certain level.⁸ Using this scenario as a back-drop, the comparative simulation below shows the results of a once-and-for-all reduction in Wyoming's effective severance tax on oil production by 2 percentage-points. Results presented have the advantage of showing how exploration and production might be expected to change over time in response to an *actual* constant policy change.

The solid lines in Figures 2–4 show the evolution of drilling, reserves, and production under the base case assumptions outlined above. Wells drilled fall steadily over time from

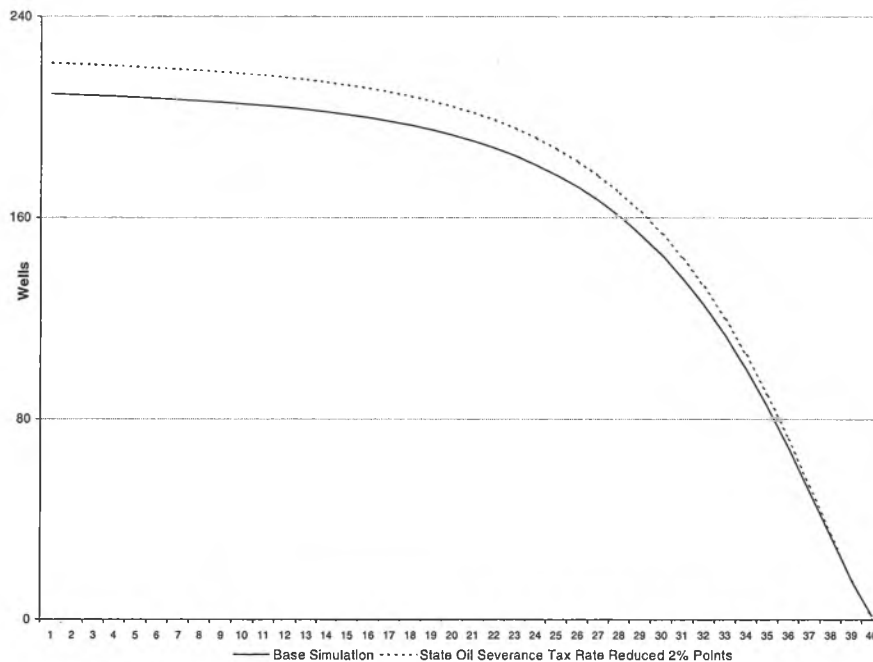


Figure 2. Wyoming oil (drilling).

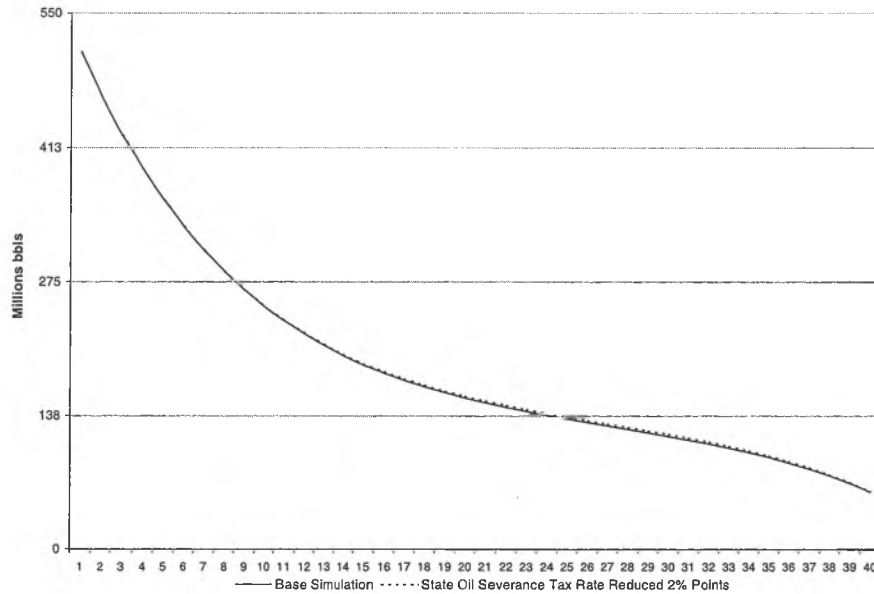


Figure 3. Wyoming oil (reserves).

209 in year 1 (2001) to 1 in year 40 (2040). Reserves also decline over this period from 510 MMbbls to 59 MMbbls with production declining from 59 MMbbls to 11 MMbbls. The dotted lines in these figures show the effects of a once-and-for-all reduction in the state oil severance tax by 2 percentage-points, which reduces the state effective rate from 5.8 to 3.8% and increases net-of-tax price by 40 cents (α_p increases by 0.016). As shown in Figure 2, the tax decrease increases drilling in the early years of the program when compared to the base simulation. Overall, drilling increases by 378 wells or 5.8% above the 40-year program base. With increased drilling in the early years, additional reserves are identified (15 million barrels more) and, as shown in Figure 3, proved reserves slightly rise in the out years.

Through the life of the program, the tax decrease results in increased production by about 14.9 million barrels, about 1.6% above the base solution. As Figure 4 depicts, this difference is roughly equal to the 15 million barrel increase in reserve additions that comes about because of the tax decrease. Also, the increase in output reflects a relatively low elasticity of production with respect to severance tax rate changes. Over the life of the program, this elasticity is approximately 0.05. Intuitively, while a decrease in the severance tax stimulates drilling activity, the additional drilling has a comparatively small effect on reserve levels. Given that over 63,000 wells (oil and gas) have been drilled in Wyoming to date 2000, prospects of a significant oil discovery are unlikely and the marginal product of drilling in finding new reserves is lower than in the past. As a consequence, reserve additions also respond inelastically to the severance tax decrease. Moreover, such small increases in

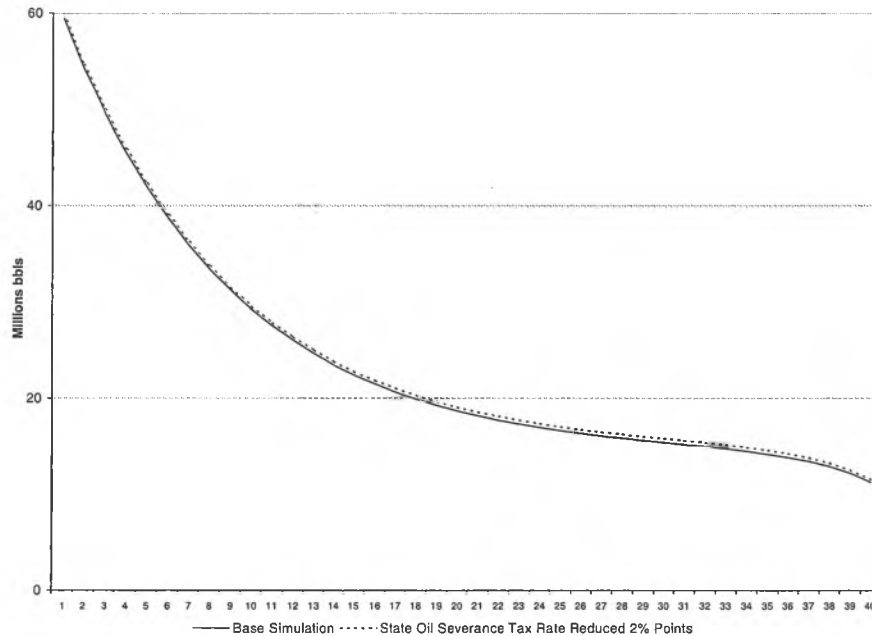


Figure 4. Wyoming oil (production).

net price (e.g., 40 cents per barrel) will unlikely affect production from existing wells and provides little incentive to reopen 'shut-in' wells.

The largest change associated with the 2 percentage-point reduction in state oil severance taxes is found in state production tax collections. Applying the discount rate of 4%, the tax change results in a decline in the present value of Wyoming state severance tax collections from \$751 million to \$498 million, a decline of over 33%. Alternatively stated, Wyoming would forego \$669,312 in present value of severance tax revenue for each of the additional 378 wells drilled. Certainly, the incentive enhanced drilling effort may provide the state other forms of benefits (i.e., short-term rig employment and sales tax collections) but these additional benefits would have to be considerable in order to offset what appears to be an insurmountable loss of state tax revenue.

Because severance taxes are deductible in computing federal corporate income tax liabilities, tax payments to the federal government increase by \$27 million (3.6% above the base case). Also, the 2 percentage-point severance tax decrease transfers state revenue to local governments because of the production stimulus. Discounted local production taxes increase by \$12 million or 2% above the base case. The same can be said for discounted public land royalties which increase by 1.9% (\$18 million) because of the increase in production. These results highlight the importance of the tax interactions described in Section 2 above.

The key result of this analysis is that oil reserve additions and production respond quite inelastically to reductions in severance tax rates. In the case at hand, a constant 2 percentage-point rate reduction increases overall simulated production by 1.6%—but decreases state severance tax revenue substantially in present value terms, by over 33%. This general outcome also applies to the other major oil producing states that levy a severance tax. In any case, oil-producing states should be wary of arguments promising large increases in oil exploration and production in response to cuts in severance tax rates.

5. Conclusions

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to allow for an empirical test of the effectiveness of state oil severance tax incentives. Equations of the model are estimated econometrically from panel data on production, exploration and reserve additions for 20 states over the period 1970–00. The model is designed so that effects of changes in existing state severance tax rates on the evolution of exploration, reserves and production can be simulated into the mid-21st century. In general, results show that severance tax rate reductions result in a substantial loss of tax revenue, moderate increases in drilling, but little change in reserve additions and production. A key question regarding this general result is: Why does output of oil respond so grudgingly to changes in severance taxes? There appears to be four reasons why this is so. First, a reduction in severance taxes offers no *direct* stimulus for reserve exploration. A cut in the severance tax, as modeled, does nothing to directly stimulate reserve additions—operators get the future benefits of this tax incentive only if they drill *and only if they are successful*. In general, “upstream” incentives given at the beginning of the exploration-development-production process may provide a greater stimulus to production than “downstream” incentives given at the end of the process—e.g., cuts in severance taxes.

Second, operators do not see the full effect of state severance tax changes because of the many tax base and rate interactions at all levels. For example, severance taxes are deductible against federal corporate income tax liabilities. Therefore, when severance tax rates fall, federal corporate income tax liabilities rise and vice-versa. In fact, results herein suggest taxes should not be analyzed independently without reference to the entire tax structure applied by all levels of government; for example, a tax discount granted at one level may be partially offset by increased liabilities at another level. Therefore, operators do not receive the full value of tax reductions that may be granted by Wyoming and other states. Third, and in a related vein, a reduction in severance tax rates by 2 percentage-points has only a small impact on the net-of-tax price received by operators. The tax reduction simulated above increases the constant net-of-tax price by only 40 cents per barrel. This small increase cannot be expected to generate much in the way of *new* oil production.

Fourth, and most importantly, production of (as contrasted with exploration for) oil is driven mainly by reserves, not by prices, severance tax rates, or tax discounts. This is a basic fact of geology and is easily illustrated by reexamining Wyoming's own history of oil production. Since 1970, Wyoming oil reserves steadily declined from 1 billion barrels to 561 million barrels in 2000 (see Figure 1). In other words, despite much exploration over the past 31 years (over 12,300 wells drilled), production has drawn down reserves faster

than new discoveries have added to them. This implies that for states like Texas, Oklahoma, and Wyoming the prospect of major exploratory success is not particularly promising (see Moroney, 1997 for a similar analysis of Texas). Moreover, during the past 31 years, oil production declined from 160 million barrels in 1970 to 61 million barrels in 2000. In fact, oil production continued to decline during the late 1970s and early 1980s even though real (year 2000 dollars) oil prices rose by a factor of more than 3, from about \$18/bbl. to more than \$55/bbl. Thus, even comparatively large price increases are not expected to call forth much additional output.

The general conclusion that severance tax changes appear to be unimportant may be problematic to public officials in oil producing states hoping to stimulate local economic activity by lowering such rates. The prospect of modest increases in exploration and production comes at a considerable cost, the loss of substantial state tax revenue that must be offset. Rather, state officials may have the incentive to raise severance tax rates risking little in the way of loss to future oil field activity.

Appendix A

This appendix derives the (generalized) constant tax parameters numbered (15)–(18) in the text. Restating the producer's problem (bracketed terms in text equation (1)) accounting for all tax effects yields

$$\begin{aligned} qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R - \tau_s[qp^* - qp^*\tau_r \\ - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R] - \tau_{us}\{qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p \\ - qp^*(1-\tau_r)\delta - C^* - \eta D^* - \tau_R R - \tau_s[qp^* - qp^*\tau_r \\ - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R]\}. \end{aligned} \quad (A.1)$$

Collecting terms from (A.1) gives

$$(1-\tau_{us})(1-\tau_s)[qp^* - qp^*\tau_r - qp^*(1-\tau_r)\tau_p - C^* - \eta D^* - \tau_R R] + \tau_{us}qp^*(1-\tau_r)\delta \quad (A.2)$$

which reduces to

$$\begin{aligned} qp^*\{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} - C^*\{(1-\tau_{us})(1-\tau_s)\} \\ - \eta D^*\{(1-\tau_{us})(1-\tau_s)\} - \tau_R R\{(1-\tau_{us})(1-\tau_r)\}. \end{aligned} \quad (A.3)$$

For a single barrel of q and R , (A.3) becomes

$$\alpha_p p^* - \alpha_c C^* - \alpha_D D^* - \gamma. \quad (A.4)$$

where

$$\gamma = \{(1-\tau_{us})(1-\tau_s)\tau_R\} \quad (A.5)$$

$$\alpha_p = \{(1-\tau_{us})(1-\tau_s)(1-\tau_r)(1-\tau_p) + \tau_{us}(1-\tau_r)\delta\} \quad (A.6)$$

$$\alpha_c = \{(1-\tau_{us})(1-\tau_s)\} \quad (A.7)$$

$$\alpha_D = \{(1-\tau_{us})(1-\tau_s)\eta\} \quad (A.8)$$

equate to equations (15)–(18) in the text.

Wyoming Tax Parameters

In developing a base simulation solution, equations (A.5)–(A.8) can be simplified because Wyoming does not have a state corporate income tax ($\tau_s = 0$) and does not levy a property tax against reserves in the ground ($\tau_R = 0$). For Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9.1% for oil in 2000. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this net value of production. Local ad valorem taxes are based on the prior year's production value. The sum of the two average effective rates in 2000 totaled approximately 12.3% (local 6.5% and state 5.8%). Also, the current nominal percentage depletion rate of 15% applied to about 52% of Wyoming oil producers in 2000, thus $\delta = 7.8\%$. Also, the expensed portion of current period drilling costs is approximately 42% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r + (q/R))$, assuming that the ratio of production to reserves is constant (see Deacon, 1993). Wyoming's mean value of q/R was approximately 11% for the sample period, therefore $\eta = 0.42 + (1 - 0.42) * (0.11/(0.04 + 0.11)) = 0.84$. The base tax policy parameters for Wyoming are $\alpha_p = 0.72$, $\alpha_c = 0.89$, $\alpha_D = 0.75$, $\gamma = 0$.

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Notes

1. Severance or production taxes are typically ad valorem taxes levied on the net production value (or volume) of a resource as it is extracted from the ground or at the final point of sale.
2. Making tax rates endogenous to the problem considered here would be a logical and important extension of this research.
3. Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987, 1988) and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ . The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are not treated in the analysis below because of severe data constraints on estimating the extraction cost function (see Section 3.2).

4. Equation (11) can be simplified by choosing a functional form for reserve additions such as the one used in Section 3 (see equation (13)). In this case, $(f_{xw}/f_w) \cdot f - f_x = 0$.
5. The Energy Information Administration and the American Petroleum Institute (2000) report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 11 smallest producing states. The 20 states included are AK, AL, AR, CA, CO, IL, IN, KS, KY, LA, MI, MS, MT, ND, NE, NM, OK, TX, UT, and WY.
6. Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).
7. Equation (13) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β . This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.
8. Wyoming rescinded this legislation in 2000.

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12.

**"State Taxation,
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STATE TAXATION, EXPLORATION, AND PRODUCTION
IN THE U.S. OIL INDUSTRY*

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STATE TAXATION, EXPLORATION, AND PRODUCTION IN THE U.S. OIL INDUSTRY

Abstract

How do firms in nonrenewable resource industries respond to changes in state taxes? This paper employs state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, affect little change in reserve additions and future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

1. Introduction

How do firms in nonrenewable resource industries respond to changes in state taxes? It may be tempting to look for answers to this question in the empirical literature on effects of state taxation (see, for example, Bartik 1985, Helms 1985, Papke 1991, 1994, and Holmes 1998). These papers focus on firms with mobile capital that choose where to locate on the basis of factors affecting revenues and costs. This perspective, however, is not particularly relevant when looking at the behavior of firms extracting nonrenewable natural resources. Such firms cannot change location because they are tied to a geographically immobile reserve base that makes up a key component of their capital stock. On the other hand, extractive firms can and probably do alter the timing of their activities when state taxes and other public policies change. Yet, little is known about the extent to which they do this even though commercially valuable deposits of natural resources are found in most U.S. states and some states such as Texas, Oklahoma, Louisiana, Wyoming, and Alaska rely heavily on taxation of oil, gas, and/or coal production to fund public services.

This paper uses state-specific estimates of Pindyck's (1978) widely cited model of natural resource supply to simulate effects of changes in state production (severance) tax policy on the timing of exploration and output by firms in the U.S. oil industry. The framework developed can be applied to any of 15 states that produce significant quantities of oil, and allows for interactions between taxes levied by different levels of government. It is arguably superior to and more comprehensive than previous efforts to develop econometric and/or simulation models of taxation and natural resource exploration and production. For example, Deacon, DeCanio, Frech, and Johnson (1990)

and Moroney (1997) focus only on one state (California and Texas, respectively), and estimate econometric equations that may not be consistent with a dynamic profit-maximizing framework. Pesaran (1990) estimates an econometric model of offshore oil production in the UK that can be better justified theoretically, but does not consider the role of taxes. Simulation studies conducted by Yucel (1989) and Deacon (1993) examine effects of various types of tax changes on exploration and production, but do not consider interactions between tax bases claimed by different levels of government. Additionally, these studies do not allow for possible interstate differences in exploration and extraction costs and are aimed mainly at assessing the generality of theoretical results obtained in more limited settings (see, for example, Burness 1976, Conrad and Hool 1980, and Heaps 1985) rather than analyzing possible outcomes of changes in state tax policies.

Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes so deadweight losses from altering these taxes are likely to be small. As a consequence, state officials may consider raising production tax rates as a way to increase revenue. It is worth noting in this context that because state production taxes are deductible against federal corporate income tax liabilities, increases in production tax rates increase state revenues partly at the expense of federal tax collections. These points are more fully discussed in Section 3 after developing the framework for the simulation model in the next section.

2. *The Simulation Model*

This section shows how Pindyck's (1978) model of nonrenewable resource development is adapted to simulate effects of state production tax changes. The

discussion begins with a brief overview of the Pindyck model and then discusses estimation of key equations and tax parameters.

Conceptual Model

The model assumes that perfectly competitive producers maximize the discounted present value of future operating profits from the sale of resources and because one such firm is chosen to represent the industry, the common pool problem and well-spacing regulations are not considered (see McDonald 1994 for discussion of these issues). The firm's problem is to take the future time path of output prices and taxes as given and then choose optimal time paths for exploration and production. This approach is similar to that taken in previously cited econometric studies of effects of changes in state tax policy on state economic growth and ignores the possibility that choices of tax bases and rates are endogenous (i.e., that governments consider the firm's objective function in choosing taxes that maximize community welfare). Also, the model defines exploration to include resource development, although the two activities clearly are not the same (Adelman 1990). The aim of exploration is to add to the reserve base, which as indicated in the introduction, is a form of geographically immobile capital.

The firm's maximization problem is

$$\max_{q, w} \Omega = \int_0^{\infty} [qp - C(q, R) - D(w) - \gamma R] e^{-rt} dt \quad (1)$$

subject to

$$\dot{R} = \dot{x} - q \quad (2)$$

$$\dot{x} = f(w, x) \quad (3)$$

$$q \geq 0, w \geq 0, R \geq 0, x \geq 0 \quad (4)$$

where a dot over a variable denotes a time rate of change, q denotes the quantity of oil extracted measured in barrels, p denotes the exogenous market price per barrel net of all taxes, $C(\cdot)$ denotes the total cost net of taxes of extracting the resource, which is assumed to depend on production (q) and reserve levels (R), $D(w)$ denotes total cost of exploration for additional reserves net of taxes, w denotes exploratory effort, γ denotes the net of all tax constant effective property tax rate on reserves, r denotes the discount rate which represents the risk-free real rate of long-term borrowing, x denotes cumulative reserve additions (discoveries), $f(\cdot)$ denotes the production function for gross reserve additions ($\dot{x}$), and $\dot{R}$ denotes reserve additions net of production (q).¹ In this formulation, the net-of-tax price per barrel is related to the wellhead (pre-tax) price (p^*) according to $p = \alpha_p p^*$, where α_p is a tax policy parameter such that $0 < \alpha_p < 1$. Correspondingly, $C(q, R) = \alpha_c C^*(q, R)$ and $D(w) = \alpha_d D^*(w)$, where α_c and α_d also are tax policy parameters that lie on the unit interval. These tax policy parameters are discussed more fully later on in this section.

Model Implementation

To implement the model, equations for exploration costs (D^*), production of reserve additions (f), and extraction costs (C^*) are estimated and then substituted into the model along with estimates of the tax parameters α_p , α_c , α_d , and γ . Effects of tax changes then are obtained by simulation. Estimates of the tax parameters are described first followed by discussion of estimates of equations for D^* , f , and C^* .

Tax Parameters

General considerations in developing estimates of the four tax policy parameters for major oil producing states are briefly outlined below and technical details are described in Appendix A. Among major oil producing states, tax structures vary considerably and tax bases interact, particularly between the state and federal level. For example, among the eight states responsible for about 89% of U.S. oil production (Alaska, California, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming), all states except California levy production taxes against the value of output. Production taxes dominate other forms of local taxation in Alaska, Wyoming, and Louisiana. Most states do not levy property taxes on the value of reserves in the ground (Texas and California do). Most states treat royalty payments (computed as a percentage of gross value of production) for production on public land as deductible items in computing severance tax liabilities (Louisiana does not). Public land royalties are prominent in Alaska, New Mexico, and Wyoming due to the large shares of publicly owned land. Most states levy a corporate income tax that applies to oil operators (Wyoming and Texas do not). Also, states have granted innumerable exemptions and credits (which differ by state) against various tax liabilities for special situations that may be encountered by operators. Within states, counties apply their own mill levies to compute property taxes on equipment at different rates. However, taxation of structures and equipment are usually less important than other sources of revenue and are ignored below.

Regarding federal taxes, all incorporated producers file federal corporate income tax returns that allow deductions for various types of operating costs and for state and local tax payments. Independent producers (those without downstream refining or retail

interests) are permitted to take a percentage depletion allowance, while major producers are allowed only cost depletion, which is significantly less generous. Both major and independent incorporated producers can expense intangible drilling costs incurred on their federal corporate income tax returns. The fact that some smaller producers are not incorporated and may therefore face alternative state and federal tax treatment is ignored.

The myriad of state-specific special features described above creates considerable complexity in tracking tax law over time. Rather than itemize tax code details, effective tax rates are used to translate dynamic tax policy into a tractable form. Effective rates can be expressed as the ratio of taxes (or royalties) collected from a particular tax to the value of production. Thus, the calculation of specific effective tax rates fully account for exemptions, incentives, different tax bases, and frequent changes in tax law both at the state and federal level. For a detail account of the taxation of the oil industry see Gerking, Morgan, Kuncce, and Kerkvliet (2000), Chapter 2.

Marginal Cost of Reserve Additions

The before-tax marginal cost of reserve additions (D_w^* / f_w) is computed from estimates of equations for drilling costs and for the production of reserve additions. Drilling costs are assumed to be proportional to drilling effort as shown in equation (5)

$$D^*(w) = \phi w e^u \quad (5)$$

where ϕ is the parameter to be estimated and the disturbance term e^u is lognormally distributed with mean of unity and variance σ_u^2 . The production function for reserve additions is specified as

$$f(w, x) = A w^\rho e^{-\beta \cdot x} e^v \quad (6)$$

where A , ρ , and β are parameters to be estimated and the disturbance e^v is assumed lognormally distributed with mean of unity and variance σ_v^2 . Equation (6) is similar to the equation describing the discovery process proposed by Uhler (1976) and later adopted by Pindyck (1978) and Pesaran (1990). The idea behind this equation is that the marginal product of exploration declines as reserve discoveries cumulate.

Estimation used annual data from the 15 U.S. states for which complete information on variables needed could be assembled for the period 1970-98.² These states accounted for 96.5% of total U.S. oil production over this time period. Drilling costs are measured by total real costs (both tangible and intangible) of each well completed, including dry holes.³ Nominal cost values were deflated using the 1995 GDP deflator. Oil reserve additions are defined as extensions, new field discoveries and new reservoir discoveries in old fields. The total number of wells drilled for each state since 1859 (when the first oil well was drilled in Pennsylvania) is used as a proxy for x . Data sources and sample means of variables used in the analysis are presented in Table 1.

Equation (5) and equation (6) were estimated in natural logarithms. Both equations used an instrument for the number of wells drilled because w is an endogenous variable in the model presented in Section 2. The instrument was obtained from the predicted values from a regression of the number of wells on cumulative drilling and the wellhead price as shown in Appendix A. Estimates of the drilling cost equation, equation (5), are obtained by regressing drilling cost per well on dummy variables for states and years. Coefficients of state and year dummies are jointly significant at the 1% level and the R^2 is 0.90. The idea behind using this approach is to get state- and time-specific estimates of ϕ . This parameter is expected to vary across states because of differences in

geologic conditions, geographic remoteness of on-shore oil resources, and whether drilling occurs in off-shore coastal waters (note that most states in the data set are landlocked). Time varying factors common to all states may include technological advancement and macroeconomic cycles. State-specific estimates of ϕ test different from each other, except Texas and Oklahoma, at the 5% level.

Estimates of equation (6), shown below in equation (7), allow for state-specific intercept terms (time-specific effects were jointly insignificant), common slope coefficients across states, and are corrected for first-order serial correlation ($\rho=0.431$).

$$\ln (ADDED\ RESERVES) = \ln A + 0.69*\ln (PREDWELLS) - 0.000006*CWELLS. \quad (7)$$

(t) (5.33) (-1.37)

State-specific estimates of A are jointly significant at the 1% level and $R^2 = 0.40$.⁴ These results show that the marginal product of drilling (f_w) decreases with wells drilled as well as with cumulative drilling, although the coefficient of cumulative drilling is insignificant at conventional levels.

Estimates of equations (5) and (6) combined show that the marginal cost of reserve additions (D_w^*/f_w) increases with drilling activity. As w increases, the marginal cost of drilling is constant, but the marginal product of drilling in finding new reserves (f_w) falls. Table 2 reports values of D_w^* , f_w , and D_w^*/f_w by state for seven major oil producing states. These estimates use 1998 values for numbers of wells drilled and cumulative drilling and are corrected for conversion from logarithms (see Greene 1997, p. 279). Estimates of D_w^* and f_w reflect considerable variation across the seven states. Estimates of marginal drilling cost range from \$127,943 in Kansas to \$1,218,758 in Louisiana. Marginal reserve additions from drilling (f_w) range from 7,460 barrels in Kansas to 64,862 barrels in Louisiana. Thus, while drilling in Louisiana is relatively

more expensive than in Kansas, Louisiana experiences a greater payoff from these more costly exploration and development efforts. Values of D_w^*/f_w for the seven states range from a low of \$17.15 per barrel in Kansas to a high of \$26.04 in Texas.

Extraction Costs

Because data on oil extraction costs are weak, $C(q, R)$ could not be econometrically estimated. Instead, this equation was calibrated for each state with a Cobb-Douglas functional form using methods described in Deacon (1993). Cost parameter calibration specifics are described in Appendix A. Results show that the 1998 marginal extraction costs range from a low of \$4.89 per barrel in Kansas to a high of \$8.81 per barrel in Louisiana. Additionally, the Cobb-Douglas form implies that extraction costs rise without limit as reserves approach zero and that a positive level of reserves will remain at any terminal time T . Thus, boundary conditions used in the simulations reported in Section 3 allow production to continue after incentives for further exploration vanish so that the terminal date for the exploration/production program must be set arbitrarily. This fixed program period could be interpreted as the producer's relevant planning horizon.

3. Simulation Results

The model presented in Section 2 can be simulated to obtain responses of exploration and production to changes in various types of taxes in any of 15 oil producing states. Simulations presented below focus on production tax changes in Wyoming. The production tax is the most important tax levied on the oil industry by oil producing states (see Section 2) and changes in production taxes turn out to have quite similar effects in all major oil producing states so results from one state are used to represent the others

(for results of tax changes in other major oil producing states, see Gerking, Kuncie, Morgan, and Kerkvliet 2000). Also, simulations reported are based on the assumption that tax changes in one state do not affect the wellhead price of oil seen by operators in other states. This assumption probably is not unreasonable in view of the fact that oil prices are internationally determined and even the largest producing U.S. state (Texas) accounts for only a small percentage (4.2% from 1970-98) of world output.⁵ Moreover, as shown below, tax changes considered lead to comparatively small changes in output, so these interstate effects are not likely to be important in any case.

Simulations for Wyoming were performed using the instrumental variable estimates of equations (5) and (6), the calibrated production cost function and the tax parameters, both derived in Appendix A. The discount rate, r , was set at 4% to reflect the risk-free real rate of long-term borrowing and the future price path was fixed at \$23.00 per barrel each year reflecting the real sample mean for all 15 states. Other price trajectories were simulated, but the alternative paths have little or no effect on the comparative results presented below. The initial value of reserves and cumulative wells drilled were fixed to year-end 1998 levels at 550 million barrels and 40,439 wells, respectively. To obtain numerical solutions for the optimal time paths of drilling, production, and reserves, difference equation approximations are derived for the time rates of change in exploratory effort ($\dot{w}$), production ($\dot{q}$), and for the state variable evolution equations (2) and (3). For example, the evolution of reserves, equation (2), is approximated by the difference, $R_{t+1} - R_t = f_t - q_t$. The model is then solved recursively by iterating over the initial values of the control variables, q and w , until transversality conditions are satisfied. Under these base conditions, exploratory effort approaches zero

after approximately 40 years, thus the terminal time is set to 40 periods. The solver algorithm in Microsoft Excel was used to generate numerical solutions.

Before the simulation results are discussed, a historical analysis of Wyoming's oil experience is warranted. Figure 1 depicts the actual time paths of real price, drilling, production, and reserves for Wyoming from 1970-98. In this figure, the vertical axis shows price per bbl (dotted line) in $\$1995 \times 10$, drilling (dashed line) in total wells, production (solid line) in $\text{bbls} \times 10^5$, and reserves (bold line) in millions of barrels (MMbbls). In reviewing these data, several observations are noteworthy. Historical drilling appears sensitive to price. Total wells drilled increases markedly during the high price period of the early 1980s. Extraction activity, however, appears to map the declining proved reserve level in the state. In fact, oil production continued to decline during the late 1970s and early 1980s even though real prices increased $2 \frac{1}{2}$ fold. The increased drilling experienced in the early to mid 1980s failed to replenish the depleting oil reserve in the state and production closely followed the reserve decline.

This apparent historical insensitivity of production to changes in price raises an interesting policy question: If severance tax changes are reflected in net price (as modeled in section 2), what are the effects of a severance tax increase? Many oil states, as previously described — including Wyoming, rely heavily on production taxes to fund local public goods and officials may have incentives to raise production taxes for the revenue. The inherent trade off to severance tax increases is the purported loss of economic activity generated by the industry within the state. To examine this, the first simulation conducted shows the effects of *doubling* Wyoming's effective state severance tax rate for the full 40-year program. Results detailing the simulated differences in the

timing of drilling, production, and discounted severance tax revenue for the full tax interaction model (outlined above) are presented in the top section of Table 3. Comparative individual program year results, divided into 10-year increments, show that doubling the state severance tax markedly decreases early period drilling. Drilling decreases by 19.4% in the first year of the simulated program and this difference converges to zero by year 40. Interestingly, 10 year fractional results show that 63.8% of the total 1208 well decrease occurs in the first 20 years of the program. Figure 2 graphically compares the effects of the tax increase (dotted line) to the base drilling solution (bold line). With less drilling in the early years of the program, fewer new reserves are identified and, as shown in Figure 3, future production of oil slightly diverges downward from the base solution. Production results presented in Table 3 show this gradual divergence — a 2.4% drop in year one falling to an 11.8% decline in year 40. Through the life of the program, doubling the state severance tax decreases total production by about 48 MMbbls or 5.7% below the base solution.

The largest change associated with doubling the state oil severance tax appears to come from discounted severance tax collections. As shown in Table 3, the tax increase results in an increase in the present value of Wyoming severance tax collections from \$609 million to \$1165 million, an increase of over 91%. The majority (87.6%) of this \$556 million increase occurs in the first half of the simulated program due to the relatively small production loss generated by the tax increase and discounting. Because severance taxes are deductible in computing federal corporate income tax liabilities, discounted tax payments to the federal government decrease by \$60 million or about 11% below the base simulation. Also, the severance tax increase transfers local government

revenue to the state because of the production decline. Discounted local production taxes decrease by \$34 million or 5% below the base solution. The same can be said for discounted public land royalties which decrease by 4.6% (\$50 million) because of the decrease in future production.

The tax interactions described above highlight a key feature of the model developed here — oil producers do not face the full effect of an increase in the severance tax rate. As shown, tax base and rate interactions partially offset the pure-effect of the severance tax rate increase. To illustrate this clearly, counterpart simulations were conducted where all tax effects, other than state level production tax rates, were effectively *zeroed out*. The lower section of Table 3 presents the counterpart Wyoming results. When all tax interactions are ignored, doubling the state severance tax decreases relative drilling by 32.8% and production by 11.2%, a decrease in activity roughly 2 times larger than found in the full tax interaction model examined above. Timing effects are similar to the full tax interaction model results. Because the severance tax increase now invokes a larger production loss, discounted state severance taxes increase by 83% as compared to the 91% increase in the full tax interaction model. Analyzing taxes individually appears to overstate the affects on exploration and production by ignoring potential offsets and tax base interactions. These results suggest that taxes should not be analyzed independently without careful reference to the entire tax structure applied by all levels of government.

General results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. This inelastic response may provide incentives for state officials to substantially increase these taxes risking little in the way of reduced

industry activity while gaining much needed tax revenue. State severance tax increases clearly reduce the net price faced by producers but it is reserves, not net price, that drives production in this industry. Moreover, the effects of increased state severance taxes are partially offset by reduced tax collections by all other levels of government.

4. *Conclusions*

This paper has adapted Pindyck's (1978) model of nonrenewable natural resource production to take account of taxation at the federal and state-local government levels. Equations of the model are estimated from panel data on production, exploration and reserve additions for 15 states over the period 1970-98. The model is designed so that effects of changes in existing state production tax rates on the timing and evolution of exploration and production can be simulated into the mid-21st century. Results of this study suggest that oil production is highly inelastic with respect to changes in production taxes. A production tax rate increase is shown to decrease early period exploration effort, invoke little change in reserve additions and subsequently future production, and substantially increase discounted tax revenue. Policy implications of this outcome suggest that state officials may consider raising production tax rates as a way to increase revenue while risking little in the way of loss to future oil activity.

Endnotes

¹Pindyck's (1978) original specification of the extraction cost function is retained here in spite of the logical inconsistencies discussed by Livernois and Uhler (1987), Livernois (1987), and Swierzbinski and Mendelsohn (1989). These authors argue that Pindyck's extraction cost function is defensible when reserves are of uniform quality but in the presence of exploration, reserves must be treated as heterogeneous because the most accessible deposits are added to the reserve base first. They show that aggregation of extraction costs across heterogeneous deposits is not valid except under special circumstances. Another problem with this function is that extraction costs should be a function of γ . The extraction cost function derived from profit-maximization at a point in time subject to a production constraint would have γ as an argument because the reserve base is an input to oil and gas production. These complications are ignored in the analysis below because of severe data constraints on estimating the extraction cost function.

² The Energy Information Administration and the American Petroleum Institute report annual production data for 31 states over this period, but data on reserve additions, cumulative drilling, and drilling costs are not available in all years for the 16 smallest producing states. The 15 states included in the panel are Alaska, Alabama, California, Colorado, Kansas, Louisiana, Michigan, Mississippi, Montana, North Dakota, New Mexico, Oklahoma, Texas, Utah, and Wyoming.

³ Major cost items are for labor, materials, supplies, machinery and tools, water, transportation, fuels, power, and direct overhead for operations such as permitting and preparation, road building, drilling pit construction, erecting and dismantling derricks/drilling rigs, drilling hole, casing, hauling and disposal of waste materials and site restoration. For additional details, see Joint Association Survey on Drilling Costs, Appendix A (1998).

⁴ Corrected (see Greene 1997, p. 279) state-specific intercept terms (and t-statistics) for 7 major producing states are: CA 0.17(2.01), KS 0.06(1.06), LA 0.57(2.21), NM 0.19(1.68), OK 0.07(1.94), TX 0.01(1.11), WY 0.29(2.03). Equation (6) was also estimated allowing for both state-specific intercepts and state-specific coefficients for ρ and β . This strategy was unsuccessful as it yielded mostly insignificant estimates of state-specific slope interactions.

⁵Source of world oil production for 1970-98, www.eia.doe.gov/emeu/international/petroleu.html.

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Table 1
Variable Definitions, Data Sources, and Sample Means
(Excludes federal OCS activity.)

<u>Variable</u>	<u>Definition</u>	<u>Source</u>	<u>Mean</u>
<i>TRCOST</i>	Total drilling cost in millions of 1995 dollars, by state and year.	American Petroleum Institute, <i>Joint Association Survey on Drilling Costs</i> . Annual.	427.6
<i>ADDED RESERVES</i>	Oil reserve extensions, new field discoveries and new reservoir discoveries in old fields, by state and year in millions of barrels.	US Energy Information Administration, <i>U.S. Crude Oil, Natural Gas and Gas Liquids Reserves Annual Report</i> . Annual	42.0
<i>WELLS</i>	Oil wells drilled in a state by year.	American Petroleum Institute, <i>Joint Association Survey on Drilling Costs</i> . Annual.	943
<i>CWELLS</i>	Cumulative total wells drilled in a state beginning in 1859.	American Petroleum Institute, <i>Petroleum Facts & Figures</i> . 1971 Ed.	1.07E+5
<i>PRICE</i>	Average well head oil price, by state and year, in 1995 dollars per barrel.	American Petroleum Institute, <i>Basic Petroleum Data Book</i> . Annual.	22.80
<i>PRICE2</i>	Average real price per barrel squared.	--	656.3
<i>CWELLS2</i>	Cumulative oil wells squared.	--	4.3E+10
<i>PRICE * CWELLS</i>	Interaction of real price and cumulative wells.	--	2.5E+6

Table 2
Pre-Tax Marginal Drilling Cost, Marginal Reserve Additions,
and Pre-Tax Marginal Cost of Reserve Additions for 7 Major Producing States

<u>State</u>	<u>D_w^* (in \$)</u>	<u>f_w (in bbls)^a</u>	<u>D_w^* / f_w^a</u>
California	274,675	11,464	23.96
Kansas	127,943	7,460	17.15
Louisiana	1,218,758	64,862	18.79
New Mexico	485,698	22,148	21.93
Oklahoma	345,706	15,223	22.71
Texas	342,266	13,144	26.04
Wyoming	593,162	34,627	17.13

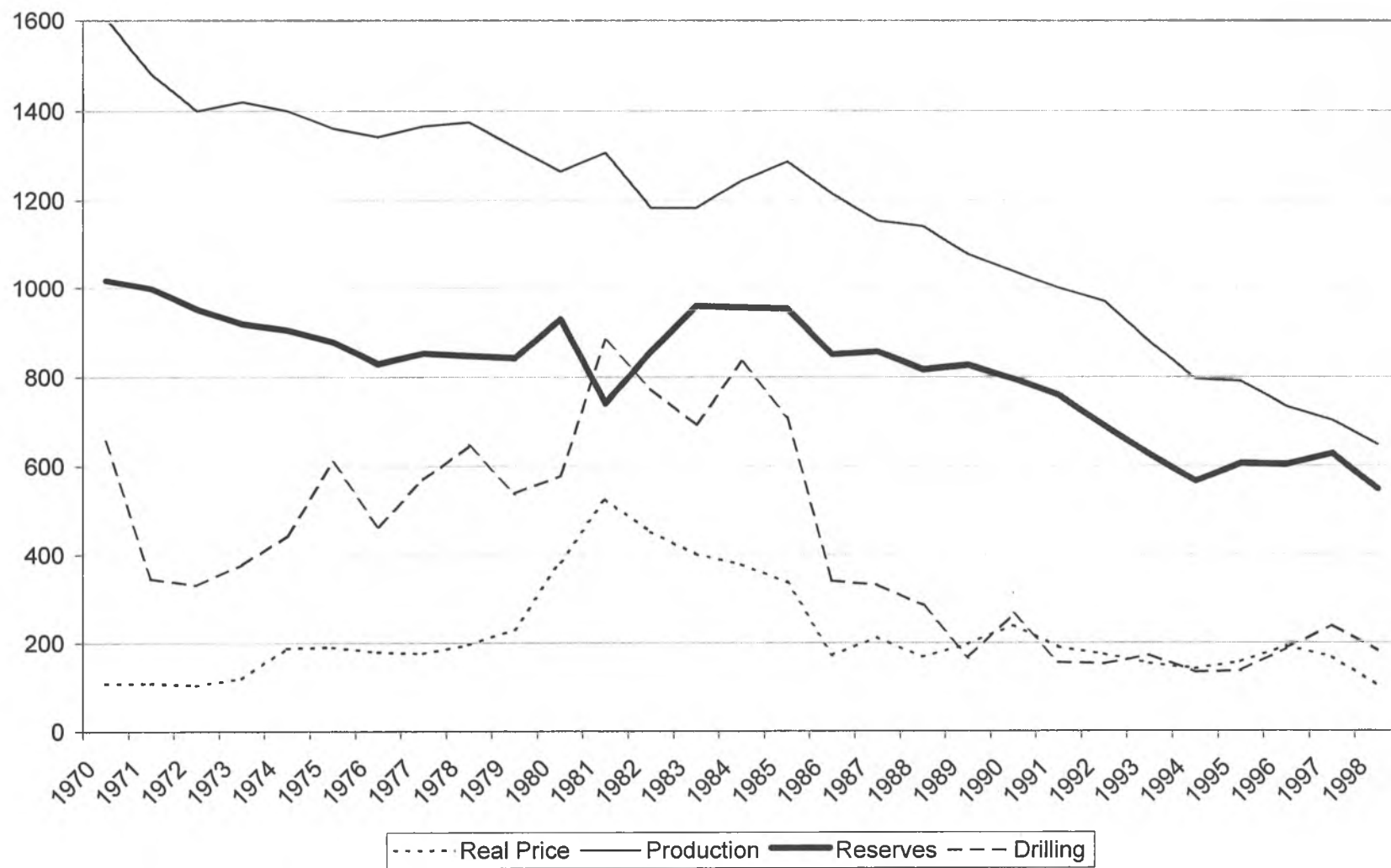
^a Assumes wells drilled at the actual 1998 count. State-specific cumulative wells total is set to actual 1998 values in all calculations.

Table 3
Timing of Drilling, Production,
and Discounted Severance Tax Revenue

<u>Full Tax Interaction Model</u>	<u>Individual Program Year:</u>					
	<u>Year 1</u>	<u>Year 10</u>	<u>Year 20</u>	<u>Year 30</u>	<u>Year 40</u>	<u>Total</u>
Drilling (Base Solution, in wells)	211	203	187	132	2	6274
Drilling (Double Tax)	170	165	152	116	2	5066
Change from Base	-19.4 %	-18.7 %	-18.7 %	-12.1 %	0.0 %	-19.2 %
Production (Base, in MMbbls)	57.7	27.0	15.9	12.1	7.6	834.3
Production (Double Tax)	56.3	25.9	14.7	10.8	6.7	786.6
Change from Base	-2.4 %	-4.1 %	-7.5 %	-10.7 %	-11.8 %	-5.7 %
Severance Tax Revenue (Base, \$MM)	66.6	21.3	8.2	4.2	1.9	608.6
Severance Tax Revenue (Double Tax)	130.2	41.0	15.2	7.4	3.3	1165.2
Change from Base	95.5 %	92.5 %	85.4 %	76.2 %	73.7 %	91.5 %
<u>10 Year Fractions of Total Change from Base Solution:</u>						
	<u>Years 1-10</u>	<u>Years 11-20</u>	<u>Years 21-30</u>	<u>Years 31-40</u>		
Drilling	33.0 %	30.8 %	25.9 %	10.3 %		
Production	21.2 %	24.8 %	27.0 %	27.0 %		
Severance Tax Revenue	67.2 %	20.4 %	8.4 %	4.0 %		

<u>No Tax Interaction Model</u>	<u>Individual Program Year:</u>					
	<u>Year 1</u>	<u>Year 10</u>	<u>Year 20</u>	<u>Year 30</u>	<u>Year 40</u>	<u>Total</u>
Drilling (Base Solution, in wells)	283	271	249	175	1	8363
Drilling (Double Tax)	189	183	168	119	1	5624
Change from Base	-33.1 %	-32.6 %	-32.4 %	-32.0 %	0.0 %	-32.8 %
Production (Base, in MMbbls)	59.6	28.8	18.0	14.2	9.0	911.0
Production (Double Tax)	57.0	26.4	15.3	11.4	7.2	809.3
Change from Base	-4.4 %	-8.3 %	-15.0 %	-19.7 %	-20.1 %	-11.2 %
Severance Tax Revenue (Base, \$MM)	75.6	24.9	10.2	5.3	2.5	714.3
Severance Tax Revenue (Double Tax)	144.7	45.9	17.4	8.6	3.9	1307.8
Change from Base	91.4 %	84.3 %	70.6 %	62.3 %	56.0 %	83.1 %
<u>10 Year Fractions of Total Change from Base Solution:</u>						
	<u>Years 1-10</u>	<u>Years 11-20</u>	<u>Years 21-30</u>	<u>Years 31-40</u>		
Drilling	33.2 %	30.9 %	25.9 %	10.0 %		
Production	21.0 %	25.1 %	26.9 %	27.0 %		
Severance Tax Revenue	68.1 %	20.1 %	8.0 %	3.8 %		

Figure 1. Wyoming Oil, 1970-98



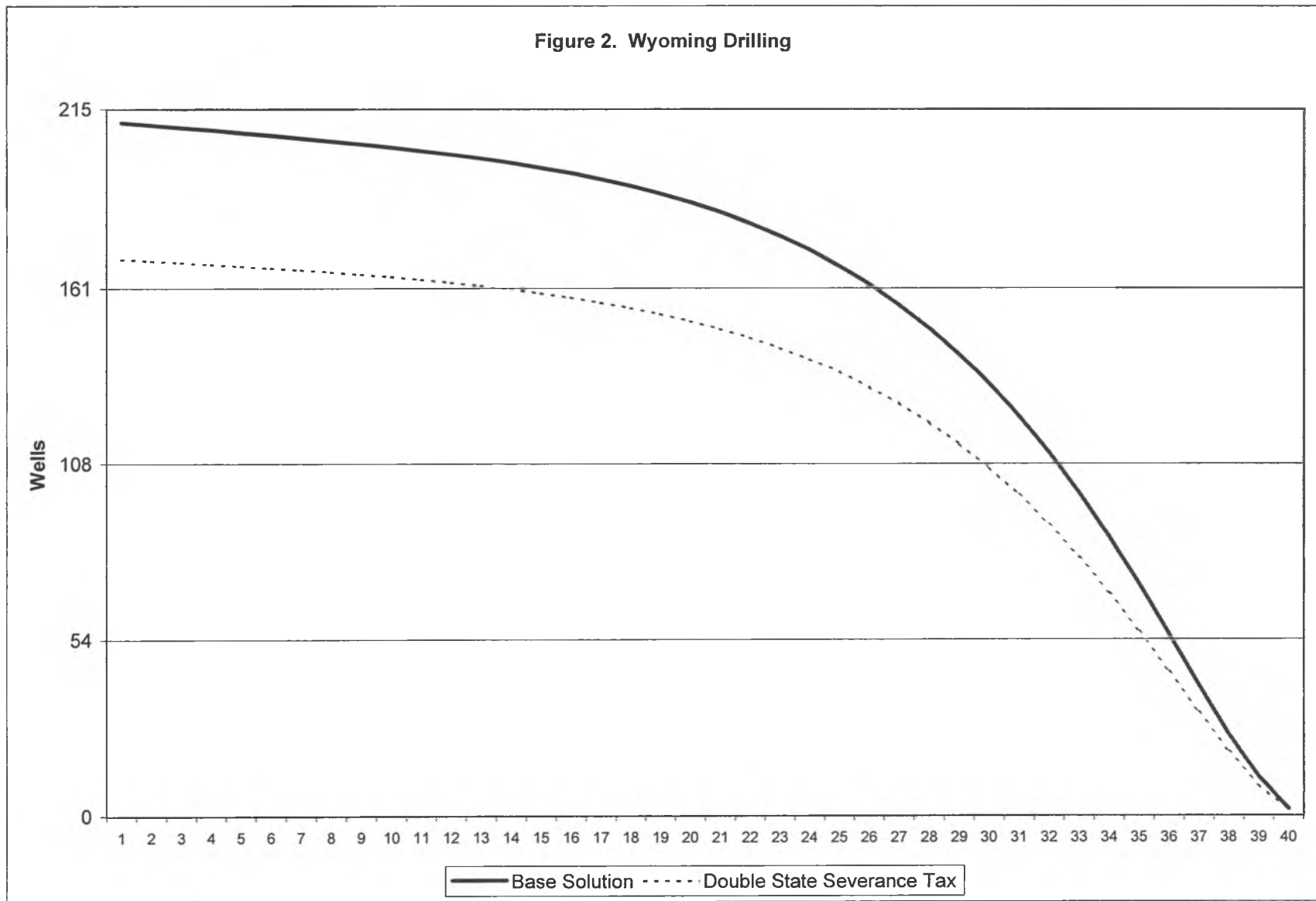
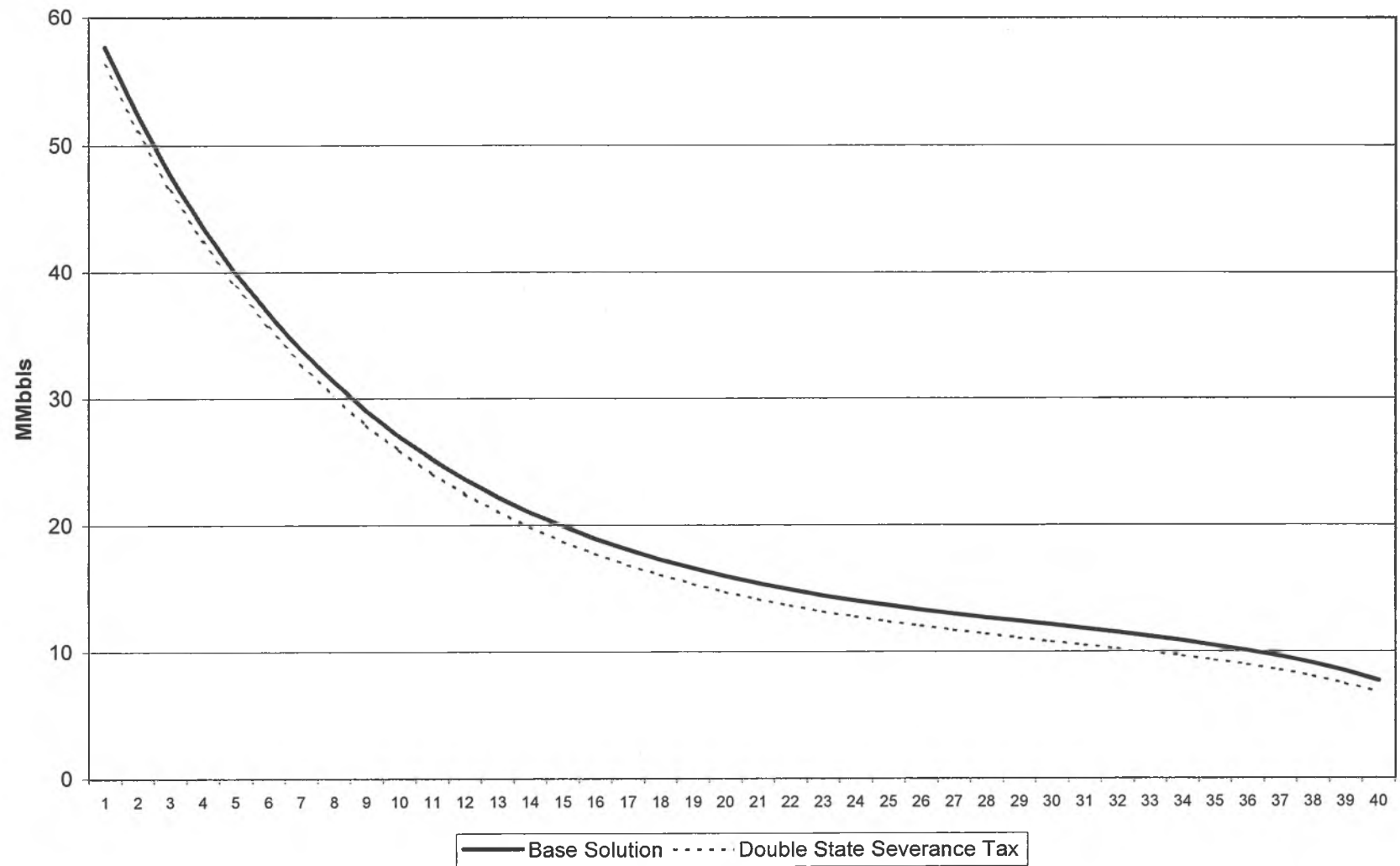


Figure 3. Wyoming Production



Appendix A

Tax Policy Parameters

For most states in most years, γ and α_j ($j=p,c,D$) can be specified by noting whether reserves are subject to a property tax (see text equation (1)) and then evaluating equations (A.1)-(A.4).

$$\gamma = \{(1 - \tau_{us})(1 - \tau_s)\tau_R\} \quad (A.1)$$

$$\alpha_p = \{(1 - \tau_{us})(1 - \tau_s)(1 - \tau_r)(1 - \tau_p) + \tau_{us}(1 - \tau_r)\delta\} \quad (A.2)$$

$$\alpha_c = \{(1 - \tau_{us})(1 - \tau_s)\} \quad (A.3)$$

$$\alpha_D = \{(1 - \tau_{us})(1 - \tau_s)\eta\} \quad (A.4)$$

A derivation of equations (A.1)-(A.4) can be found in Gerking, Morgan, Kuncce, and Kerkvliet (2000), Appendix C. In (A.1)-(A.4), τ_{us} denotes the federal corporate income tax rate, τ_s denotes the state corporate income tax rate, τ_R denotes the property tax rate on reserves weighted by the per unit assessed value, τ_r denotes the royalty rate on production from public (state and federal) land, τ_p denotes the production (severance) tax rate, δ denotes the federal percentage depletion allowance weighted by the percentage of production attributable to eligible producers (nonintegrated independents), and η denotes the expensed portion of current and capitalized drilling costs attributable to current period revenues. η is made up of two components: (1) the percentage of current period drilling costs expensed and (2) the estimated present value of cost depletion deductions for the capitalized portion of current and past drilling expenditures. Producers are allowed to expense costs associated with drilling dry holes along with certain intangible costs (e.g., labor and fuel) for completed wells as they are incurred. All direct

(tangible) expenditures for completed wells must be capitalized then depleted over the life of the producing well. In the illustration at hand, equations (A.1)-(A.4) can be simplified because Wyoming does not have a state corporate income tax ($\tau_s=0$) and does not levy a property tax against reserves in the ground ($\tau_R=0$).

This formulation captures several aspects of the U.S. tax structure as it applies to the oil industry. (1) Federal royalty payments are deductible in computing state production tax liabilities. (2) Federal royalty payments, state production taxes, state property taxes on reserves, extraction costs, and certain drilling costs (described above) are deductible in computing both state and federal corporate income tax liabilities. (3) State corporate income taxes are deductible against federal corporate income tax liabilities. As noted in text section 2, state tax treatment of the oil industry is not uniform and there are a number of situations in which these equations would have to be modified. Notice that this treatment of taxes in the model highlights the interaction between tax bases and is more detailed than the corresponding treatment given by Moroney (1997) or Deacon, DeCanio, Frech, and Johnson (1990). Also, the entire tax structure is incorporated into the model, rather than simply analyzing one tax at a time as in Deacon (1993).

All tax parameters in equations (A.1)-(A.4) are effective rather than nominal rates. States grant numerous credits and exemptions against taxes levied, so nominal rates generally overstate amounts actually paid. State and local data required for these effective rate calculations are neither available from a central source nor compiled in a common format, so they were obtained directly from tax officials in each state (see Gerking, Morgan, Kuncle, and Kerkvliet 2000, Chapter 2). In developing the *base*

solution for Wyoming, royalty rates are computed as the sum of state and federal royalty payments divided by the gross value of production and averaged 9% for oil in the late 1990s. This percentage is higher than for other oil producing states because of the comparatively large share of Wyoming's production on public lands. Production tax rates are computed as total production tax collections divided by the prior year's gross value of production net of public land royalties. In Wyoming, there are both local and state levies against this one-year-lagged net value of production. The sum of the two average effective rates in the late 90's totaled approximately 11.9% (local 6.7% and state 5.2%). At the federal level, data from Statistics of Income (U.S. Department of Treasury, 1997-1998) for the oil and gas sector show that federal corporate taxes paid averaged about 10% of *net operating* income in 1998. Also, the current nominal percentage depletion rate of 15% applied to about 58% of Wyoming oil producers in 1998, thus $\delta = 8.7\%$. Also, the expensed portion of current period drilling costs is approximately 40% for the industry and the present value of depletion deductions for capitalized drilling cost can be approximated by $(q/R)/(r+(q/R))$, assuming that the ratio of production to reserves is constant (Deacon 1993). Wyoming's mean value of q/R was approximately 8% for the sample period 1996-1998, therefore $\eta = 0.40 + (1 - 0.4)*(0.08 / (0.04 + 0.08)) = 0.8$. The base tax policy parameters for Wyoming are $\alpha_p = 0.73$, $\alpha_c = 0.90$, $\alpha_D = 0.72$, $\gamma = 0$.

Estimate of an Instrument for WELLS

An instrument for the natural logarithm of *WELLS* was used as an explanatory variable in estimating both text equations (5) and (6) with *CWELLS* entering equation (6) as the proxy for x . Instrumental variable estimation is appropriate because w is an endogenous variable in the model presented in Section 2. An instrument for w was

obtained by predicting the natural logarithm of the number of wells drilled from the one-way fixed-effects regression reported in Table A.1. Time-specific effects tested insignificant at conventional levels and $R^2 = 0.91$. *PRICE* and *CWELLS* were included as explanatory variables because they are exogenous variables in the model. *PRICE2*, *CWELLS2*, and *PRICE*CWELLS* were included to account for non-linearities expected in light of relationships in the model (see Table 1 for descriptions). All estimated coefficients are significantly different from zero except the interaction term *PRICE*CWELLS*. The marginal effect of *WELLS* with respect to *PRICE* increases at a decreasing rate. The Pearson correlation between the actual values of $\ln(WELLS)$ and the corresponding predicted values, $\ln(PREDWELLS)$, is 0.96.

Table A.1
Construction of Instrument $\ln(PREDWELLS)$

<u>Explanatory Variable</u>	<u>Coefficient (t-statistic)</u>
<i>PRICE</i>	0.064 (6.49)
<i>PRICE2</i>	-0.45E-3 (-2.90)
<i>CWELLS</i>	-0.22E-4 (-5.19)
<i>CWELLS2</i>	0.15E-10 (4.17)
<i>PRICE*CWELLS</i>	0.18E-7 (1.51)

Extraction Cost Function

Direct operating (lifting) cost for oil by region at depths of 2,000, 4,000, 8,000, and 12,000 feet are available from annual cost index studies published by the DOE/EIA

for the period 1970-1998. However, these data are of limited value for two reasons. First, cost estimates are not always disaggregated to the state level and cost estimates for other states may not be representative of all production. Second, through the mid-1980s, price controls on oil and/or gas distorted production incentives, making historical extraction costs difficult to compare with extraction costs in more recent years. As a compromise, following Deacon (1993), values of extraction cost parameters are calibrated for the following Cobb-Douglas function,

$$C(q, R) = \kappa q^{\varepsilon} R^{1-\varepsilon} , \quad (\text{A.5})$$

where $\varepsilon = 1/\mu$, μ is the production share of non-reserve inputs, and κ is a constant value that drives the production cost modeled to an average level of *lifting costs* representative of the 1998 DOA/EIA surveyed estimates described above. State-specific estimates for μ are established from the data on operating cost, drilling cost, production, reserve additions, and reserve levels described above (see Kunce, Gerking, and Morgan 2001 for specific calibration methods). Marginal extraction costs per barrel using 1998 data for 7 major producing states are: CA \$6.12, KS \$4.89, LA \$8.81, NM \$6.27, OK \$6.89, TX \$6.71, and WY \$6.43. The 1998 calibrated oil production cost parameters for Wyoming are $\varepsilon = 2.93$ and $\kappa = 141$.

13.

**Gas and Water
Handling
Constraints
handout**

Gas and Water Handling Constraints On Alaska's North Slope

Excerpts from Articles and Reports, 1989-2011

Background Information

1989 Revenue Sources Book

Alaska Department of Revenue

"The vast majority of Alaska production will continue to come from the now declining Prudhoe Bay field ... The decline in Prudhoe Bay production is now expected to be much more rapid than assumed in our Spring forecast. This reflects a more serious gas handling constraint. As more and more gas is produced with each barrel of oil, the amount of gas which must be re-injected back into the Prudhoe Bay field has increased substantially. Since it is anticipated that there will need to be more production downtime due to field and TAPS maintenance, the gas handling constraint will limit the ability to keep average annual oil production from falling. Installation of additional gas handling equipment, GHAX1 (gas handling and expansion 1), is scheduled to start late in 1990. A second expansion is in the planning stages. Once in place, the ability to re-inject up to 5.1 bcf/day of gas production will slow the rate of decline in oil production."

A Production Optimization System for Western Prudhoe Bay Field, Alaska

By D.A. Barnes, K. Humphrey, and L. Muellenberg of BPX America

Paper prepared for presentation at the 65th Annual Technical Conference and Exhibition of the Society of Petroleum Engineers held in New Orleans, LA, Sept 23-26, 1990.

"For almost a decade the Prudhoe Bay field on the North Slope of Alaska has produced at a yearly average offtake rate of 1.5 million stock tank barrels of oil per day. As the reservoir depletes and field gas-oil ratios (GORs) increase, gas handling constraints make it difficult to achieve oil rate targets."

With Prudhoe Bay in Decline, What's Next for Alaska?

By James M. Davis (Senior Vice President for Exploration and Land) & Jerry R. Pollock (Manager, Prudhoe Bay Engineering) of ARCO Alaska, Inc.

Oil & Gas Journal, August 3, 1992

"By any definition, Prudhoe Bay is declining and will continue to decline ... To accountants, Prudhoe decline began during 1988 when the field was no longer able to make its maximum allowable rate of 1.5 million b/d of oil. To engineers, the decline

began long before that ... Unfortunately, adding more wells can't keep the oil production rate up forever. We're already past the point where drilling can stave off a falling oil rate ... As the field matures, the production facilities reach their maximum capacities to handle produced water and gas. Wells with falling oil rates and increasing produced water or gas volumes have to be shut-in. Total field oil production drops."

Prudhoe Bay: Development History and Future Potential

By D.J. Szabo, BP Exploration (Alaska) Inc. and K.O. Meyers, ARCO Oil and Gas

Paper prepared for presentation at the SPE 1993 Western Regional Meeting, Anchorage, AK, 26-28 May 1993.

"Prudhoe Bay is seen by many as a mature oil field on an inevitable and irreversible decline ... The field's oil production capacity dropped below 1.5 MMSTB/D in 1988 *officially* signaling the start of decline. The onset of decline was a direct result of limited gas handling capacity as opposed to limited oil production capacity."

Alaskan North Slope Focus Shifts from Wildcats to Cutting Production Costs

Oil & Gas Journal, June 6, 1994

"Liquids production at Prudhoe Bay is constrained by the ability of field operators to process and reinject associated natural gas. Since 1988, the field's production has declined to 1.1 million b/d from 1.6 million b/d of hydrocarbon liquids. Installation of additional gas handling capacity will temporarily stem the decline in the near term and slow the rate of decline in the years ahead."

Prudhoe Bay Field: Facility Consolidations Pave the Way for an Economic Future

By K.D. Eager, BP Exploration; M.D. Briscoe, ARCO Alaska; R.A. Bolduc, Exxon

Paper prepared for presentation at the 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, LA, 27-30 Sept 1998.

"The Prudhoe Bay Field on Alaska's North Slope has produced for twenty-one years. Prudhoe's gas and water production rates are at historic highs, but the oil production rate has declined to less than one-half of the peak rate achieved in the 1980s. As a result, significant excess oil treating capacity exists, with water and gas handling capacity constraining the current oil production rate. The owners of the Prudhoe Bay Unit developed a major facility consolidation plan in 1997 designed to rationalize this excess oil treating capacity while preserving existing gas and water handling capacity. The reconfigured facilities are expected to provide sufficient capacity at a lower cost to

accommodate projected oil, water and gas production rates over the remaining life of the Prudhoe Bay Field."

Optimization of Production from Mature Fields

By P. Wang & K. Aziz of Stanford University and M.L. Litvak of BP, USA

17th World Petroleum Congress, September 1 - 5, 2002, Rio de Janeiro, Brazil

"Oil production in the Prudhoe Bay and Kuparuk River fields is constrained by the gas handling limits of the surface facilities."

2003 Oil and Gas Report (for the period ending December 31, 2002)

Alaska Department of Natural Resources (Tom Irwin, Commissioner)

Division of Oil and Gas (Mark Myers, Director)

"From the beginning of Prudhoe Bay production, dissolved gas and water were separated from the crude oil and injected back into the reservoir. Over time the reservoir's proportion of both gas-and-water to oil increased. Eventually, oil production was constrained by the rate at which the separating plants could process gas and water."

North Slope of Alaska Facility Sharing Study

Prepared for Division of Oil & Gas, Alaska Department of Natural Resources

By Petrotechnical Resources Alaska, May, 2004

"The North Slope processing facilities have specific design capacity limits, indicating the amount of oil, water and gas which can be handled by the facility. If the handling capacity of one of these streams is reached for a given facility, it limits the overall production output from that facility. While some facilities may be producing below capacity for oil, they are often limited due to capacity constraints on total water production or gas production."

Alaska Oil Forecast Shaky

By Kristen Nelson, Petroleum News

Week of November 18, 2007

"While new oil is an issue in maintaining production levels, there are also issues at existing fields, where [Dudley] Platt said facilities expansion may be needed. He said the large facilities are 'maxed out on how much gas they can handle and they're getting

close to being maxed out on how much water they can handle. ... If they don't expand their facilities to handle that, the oil production will continue to go down.'"

Optimized EOR Design for the Eileen West End Area, Greater Prudhoe Bay

By M.N. Panda, SPE, Petrotechnical Resources of Alaska; J.G. Ambrose, BP Alaska; G. Beuhler, TNK-BP; and P.L. McGuire, BP Alaska

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"Eileen West End (EWE) initially was developed in the same style as Prudhoe Bay. To accomplish this, excess produced gas from Prudhoe Bay was injected into the EWE gas caps with a hope that the reservoir would produce with effective gravity drainage in a manner similar to that of Prudhoe Bay. Conductive faults and shale barriers, however, led to unexpected early gas breakthrough. High gas/oil ratios reduced the oil production rate, leading to a reduced recovery factor from the field."

New Developments in Upstream Oil and Gas Technologies

Hearing before the Committee on Energy and Natural Resources, United States Senate

Testimony by Kevin Banks, Director, Division of Oil and Gas, Alaska Dept of Natural Resources
May 10, 2011

"With the exception of development of heavy oil resources known to exist around the Prudhoe Bay, Kuparuk, and Milne Point fields, and potential resource plays (like the Bakken in North Dakota) that may exist on the North Slope on State controlled lands, the natural field declines cannot be replaced without access to production from Federal lands and the OCS. There are no known conventional resources on State or Native lands that are likely sufficient to replace the decline in the existing production rates."

Memo to Senator Joe Paskvan

From DNR Division of Oil and Gas

Re: North Slope Facilities Expansion

June 8, 2011

"... it is our belief that additional gas and water handling capacity investments will be necessary in some cases for continuing operation of maturing fields, development and expansion of satellite reservoirs, and to allow for facilities sharing with other new developments outside of current Units."

14.

**North Slope of
Alaska Facility
Sharing Study**

North Slope of Alaska Facility Sharing Study

**Prepared for
Division of Oil & Gas
Alaska Department of Natural Resources**



May 2004

**By Bob Kaltenbach, Chantal Walsh, Cathy Foerster, Tom Walsh,
Jan MacDonald, Pete Stokes, Chris Livesey and Will Nebesky**



www.petroak.com

North Slope of Alaska Facility Sharing Study

Executive Summary

I. Introduction

II. Guiding Principles for Facility Sharing Practices

III. Physical Considerations

North Slope Overview

Projected Production and Pipeline Constraints and Excesses

Areas of Independents' Interest and Activities

IV. Facility Sharing Negotiation Specifics

Guideline for Negotiation Strategy Template

Backout Methodology Guidelines

Backout Method alternatives

V. Commercial Considerations

Commercial Framework

Existing North Slope Facility Sharing agreements

Kuparuk

Endicott

PBU and Pt Mac/Lisburne

Facility Sharing Analogs

North Sea's Indicative Tariff Methodology

Alberta's Facility Sharing Agreement, the Jumping Pound Formula
90/95

Independent Oil Companies perspectives

VI. Recommendations

Appendices

List of Figures

Figure	Page
1. North Slope Facilities Map*	Facing page 8
2. Generic Processing Flow Schematic	8
3. Alpine Simplified Processing Flow	10
4. Badami Simplified Processing Flow	11
5. Endicott Simplified Processing Flow	12
6. Kuparuk Simplified Processing Flow	13
7. Milne Pt. Simplified Processing Flow	14
8. Northstar Simplified Processing Flow	16
9. North Slope Pipelines and TAPS*	Facing page 19
10. Badami Pipeline shipping rates and capacity	20
11. Endicott Pipeline shipping rates and capacity	20
12. Milne Pt. Pipeline shipping rates and capacity	21
13. Alpine Pipeline shipping rates and capacity	21
14. Kuparuk Pipeline shipping rates and capacity	22
15. Northstar Pipeline shipping rates and capacity	22
16. TAPS Pipeline shipping rates and capacity	23
17. Recent North Slope exploration activity*	Facing page 24
18. Hypothetical Backout Illustration*	34
19. Backout Concept	35

* Graphics created by Division of Oil and Gas

List of Tables

Table	Page
1 Alpine facility operation vs. capacity	9
2 Badami facility operation vs. capacity	10
3 Endicott facility operation vs. capacity	12
4 Kuparuk facility operation vs. capacity	13
5 Milne Pt. facility operation vs. capacity	14
6 Northstar facility operation vs. capacity	15
7 Pt. McIntyre/Lisburne facility operation vs. capacity	16
8 Prudhoe Bay facility operation vs. capacity	17
9 North Slope pipeline capacities and future production	18
10 Summary of N.S. facility capacities and constraints	23
11 Example of Potential Costs	32

Executive Summary

Facility sharing is critical for the future of the oil and gas industry on the North Slope.

This study was commissioned by the Alaska Department of Natural Resources, Division of Oil and Gas to address issues associated with processing facility sharing agreements for future North Slope activity. The goals are: to characterize the existing facilities, their current throughput, and their theoretical capacities; to identify the needs and desires of independent producers and North Slope facility owners and operators; to describe how facility access is managed in other oil and gas provinces; and to develop guidelines for facility access on the North Slope. Exploration and drilling activities are not addressed in this study. Only issues related to facility sharing and availability of space in pipelines are addressed in this report.

Petrotechnical Resources of Alaska (PRA) prepared this report by: compiling existing facilities data from BP Exploration (Alaska), ConocoPhillips Alaska, and ExxonMobil; identifying capacity issues; surveying independent oil companies; reviewing existing facility sharing agreements; and preparing guidelines for third-party access to facilities.

While many North Slope processing facilities have spare capacity for oil, water, or gas handling, most facilities have reached capacity for handling at least one of these components. A summary of facility constraints and excess capacities at the field level includes:

1. Alpine currently meets capacity for oil, gas, and water injection, and planned facilities expansions likely will be filled by Alpine satellite development (Fjord, Nanuk, etc).
2. Badami is in warm shutdown, and theoretically has space available up to design capacities,
3. Endicott currently has spare oil capacity, but water and gas are at capacity limits,
4. Kuparuk currently has spare oil capacity, but water, total liquid and gas are at capacity limits,
5. Milne Pt. has oil and gas capacity available through 2015, water capacity until 2011,
6. Northstar has capacity available in oil and water handling, and will reach gas capacity by 2006,
7. Lisburne Production Center is currently at or near both gas and water capacity,

8. Prudhoe Bay facilities have room for oil, but gas production is at capacity limits and water handling is at or approaching capacity limits in all facilities.
9. Pipeline capacity for Alpine is full; Kuparuk, Milne Pt, Northstar, and Lisburne/ Pt. Mac are nearly full; and Badami, Endicott, and Prudhoe Bay have pipeline capacity available.

The reference facility sharing agreement suggested herein by PRA is based largely on Ballot No. 255 for Kuparuk, which has served as the standard for several subsequent North Slope facility sharing agreements. The PRA reference agreement includes examples of potential costs associated with facility access.

Only Kuparuk River, Prudhoe Bay, Lisburne, and Endicott production facilities have existing facility sharing and services agreements addressing satellite production. The existing facility sharing agreements, while created with only unitized production in mind, are de-facto templates for recent access negotiations. The joinder agreement (Appendix D) between Winstar and the Kuparuk River Unit is an example of the use of Ballots 255, 255A, and 260 for the Kuparuk River Unit allowing for third-party satellite production.

The guiding principles from the United Kingdom (U.K.) Code of Practice and Alberta's Jumping Pound formula have much in common with the existing North Slope facility sharing agreements. However, the U.K. and Alberta contracts provide for regulatory interdiction as needed to resolve disputes between negotiating parties, although emphasis on a cooperative approach to facility sharing has been successful in negating the need for government interdiction. Existing agreements between unit partners on the North Slope present the starting point for new third-party facility sharing agreements, and an understanding of these agreements will aid potential third-party producers in negotiating new agreements.

A survey of 15 independent oil companies currently interested in Alaska oil and gas exploration indicates that their primary concerns regarding access to existing facilities include: backout calculations, access fee methodology, timeliness of access negotiations, insurance requirements, and operatorship issues.

The report concludes that: 1. Interested parties should be able to negotiate an acceptable agreement and negotiations should be initiated as early as prospect maturity allows; 2. Development and communication of a process for facility access which is fair and

transparent will help to resolve any lack of trust, and create opportunity for expanded resource development; 3. Potential third-party producers need to provide operators with a well thought-out development plan and crude characteristics to support any request for facility access; 4. Facility operators need to communicate the backout methodology and terms, and respond to requests for access costs in a timely manner; 5. It must be recognized that backout is a valid concept , representing real lost or deferred barrels to the facility owners, for which reasonable compensation is justified; 6. Agreement must be reached on a simplified backout methodology for fields without a detailed dynamic plant model; and 7. The State of Alaska has options to help defray the impact of backout fees, and this may prove to be a decisive factor in the success of North Slope facility sharing.

North Slope of Alaska Facility Sharing Study

Introduction

The State of Alaska, the North Slope operators and the companies having or seeking to purchase leases on the North Slope all recognize the need for business cooperation and efficient use of resources to maintain a vibrant North Slope oil and gas industry. The continued and increased production of North Slope crude oil and gas is a goal of all parties. This study addresses issues associated with the processing facility sharing agreements for future North Slope activity. The study characterizes existing facilities and their processing potential, identifies the needs and desires of independent oil and gas companies and North Slope facility owners and operators, and lays the groundwork for designing a template for successful facility access on the North Slope of Alaska which benefits all parties involved.

PRA believes that there is mutual benefit to the facility owners and third-party producers in adopting reasonable terms for facility access which are equitable and understandable. In other mature basins, such as the North Sea, facility owners offer an “Indicative Tariff”, or ballpark figure for facility access cost to interested producers. A survey of interested independent oil and gas explorers was undertaken to gather their issues and concerns about the future development in Alaska (Appendix A). The North Slope operators responded to facility information and data request (Appendix B). PRA compiled these various data and information in preparation for this report.

The list of deliverables provided is:

- Definition of existing facilities and design capacity for: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Pt Mac/Lisburne, and Prudhoe Bay Fields.
- Identification of constraints and excess capacity for: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Pt Mac/Lisburne, and Prudhoe Bay Fields.

- Identification of facilities currently operating at capacity and areas that may need higher capacity based on satellite exploration activity.
- Compilation and communication of the North Slope facility owners/operators perspective on facility sharing.
- Assessment of facility sharing and back-out costs including a negotiation strategy template, and a review of facility sharing agreements in other places.
- Compilation and communication of the current Independent oil companies' perspective on facility sharing.

The issue of facility sharing is critical for the future of the oil and gas industry on the North Slope. A successful facility sharing agreement must provide a solution that is mutually satisfying to all parties. The existing owners and operators, the Independent producers looking to be active on the North Slope, and the State of Alaska all have a vested interest in seeing a process that enhances the oil and gas industry.

Potential producers have the burden of exploring and bringing the crude to the surface, negotiating a facility sharing agreement for the processing of their fluids, and transporting or establishing a custody transfer agreement at the outlet of the facility. The exploration and drilling activities have their own significant challenges, which are not addressed in this study. Only facility sharing issues and transportation issues, as they relate to availability of space in pipelines and tankers, are addressed in this report.

The PRA team analyzing and reviewing this study included the following individuals:

Cathy Foerster	Reservoir Engineer
Robert Kaltenbach	Facility Specialist/Cost Analyst
Jan MacDonald	Reservoir Engineer/Commercial Analyst
Chantal Walsh	Petroleum Engineer
Tom Walsh	Project Manager/Geophysicist
Pete Stokes	Petroleum Engineer/Business Consultant
Chris Livesey	Geologist

A tremendous amount of data and support to this study was provided by the North Slope Facility Owners and Operators: BP Exploration (Alaska) Inc., ConocoPhillips Alaska, Inc., and ExxonMobil. Additionally, the following Independent Oil companies submitted valuable insight and ideas to this evaluation: Winstar, Talisman, Alaska Venture Capital Group, Kerr McGee, and DevonCanada.

Guiding Principles for Facility Sharing Practices

Facility sharing is a key component in the future viability of the oil and gas industry on the North Slope and in order for successful sharing to take place, real mutual benefit to all parties must be demonstrated. Given the complexity of the business drivers represented by the parties, demonstration of mutual benefit is not a trivial exercise and it is helpful to define a basic set of guiding principles for facility sharing on which all parties can agree. Below is a list of guiding principles compiled from oral and written communication from a cross-section of contributors to this study, including facility owner and operator companies, potential third-party producers, and State of Alaska government officials.

The facility sharing process must:

- Be fair, equitable, and understandable to all parties
- Result in net increase in production, improve resource conservation, and reduce waste
- Not result in any new government regulation
- Preserve and promote operational integrity
- Preserve the integrity of unit rights/obligations, and tax partnerships
- Reduce financial and operational risk
- Introduce no significant adverse impact to existing production
- Provide timely access to indicative fee structure for bona fide inquirers
- Create a level playing field for all producers, where the “best” barrels are produced
- Allow for resolution of conflicts
- Compensate the facility owners for their historical capital costs and lost or deferred production
- Provide equitable sharing of ongoing costs among all users

Physical Considerations

Potential producers are faced with the burden of exploring for oil and gas, bringing it to the surface, processing their fluids either with their own facilities or negotiating a facility sharing agreement, and transporting or establishing a custody transfer agreement at the outlet of the facility. If the third party producers build their own processing facilities, the product stream will need to tie into a pipeline for transportation. The common carrier pipelines will accept the production as long as it meets their specifications.

The North Slope processing facilities have specific design capacity limits, indicating the amount of oil, water and gas which can be handled by the facility. If the handling capacity of one of these streams is reached for a given facility, it limits the overall production output from that facility. While some facilities may be producing below capacity for oil, they are often limited due to capacity constraints on total water production or gas production. In this case, additional production can be introduced into the facility by backing out existing wells, such as those with high GOR or WOR, and processing third party production of oil with lesser amounts of water and/or gas. The facility-owner's production volume that is deferred due to the introduction of third party processing is referred to as "backout" or "backout volume". Compensation for this backout volume is an item of particular interest in negotiating a facility sharing agreement. The method of calculating this backout volume is detailed later in the report.

Where facilities are producing at peak oil handling capacity, backing out high GOR or WOR oil will not result in additional oil production, and backout costs for satellite producers would be prohibitive. Additionally, the pipelines necessary for transporting the produced fluids must have room for additional volume if new production is to be introduced. It is essential to remember that, even if there is available processing capacity in the facilities, there must be room for additional oil in the downstream pipeline system to accommodate satellite production. (See section on pipeline volume and forecasts.)

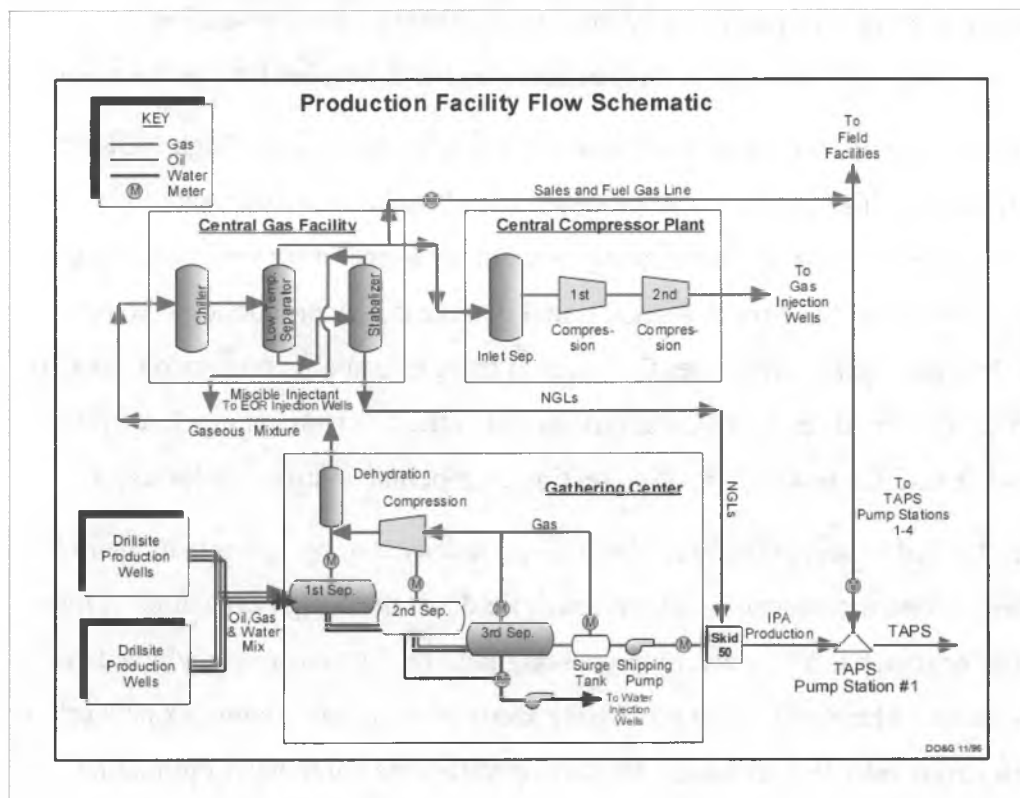
The first step toward understanding the North Slope facility sharing issues is to identify the processing infrastructure associated with each field and the design capacities of these facilities. The next step is to review, by processing facility, the constraints which drive the capacity limits. The North Slope processing facilities represent a complex network of systems with strong interdependencies. Facility operators are continually optimizing

production parameters to maximize sales oil volume and minimize cost, managing individual well production for hundreds of wells to match plant specifications and pipeline and tanker capacities. To understand how and where third party oil can be processed, all of these factors need to be considered.

North Slope Overview

There are eight primary operating areas on the North Slope of Alaska that currently process North Slope oil and gas (See Figure 1). These eight facilities are: Alpine, Badami, Endicott, Kuparuk, Milne Point, Northstar, Point McIntyre/Lisburne, and Prudhoe Bay. Northstar and Endicott are on man-made islands. Generally, the facilities consist of oil/gas/water separation, gas dehydration/compression/reinjection, water treatment/reinjection, and in some cases, NGL production. For a generic process flow diagram, see Figure 2. Individual facility process flow diagrams are shown in Figures 3 – 8. Oil is transported from each of the facilities into common carrier pipelines. The design capacities of each specific facility are shown below and compared with their current operating conditions. The forecast shows whether it is likely or unlikely that any new satellite production would incur backout costs.

Figure 2 **Generic Facility Flow Diagram**



Alpine

There is currently one producing pool (Alpine Participating Area) in the Colville River Unit (CRU). The major components of the basic facilities used by the CRU are: Alpine Processing Facility, Two Drillsites (CD-1 and CD-2), Alpine Pipeline, Seawater Treatment Plant (STP) pipeline, (Under a special agreement, STP supplies waterflood water to the CRU), the Alpine Main Camp, Spill Response Center, Warehouse, Airstrip, diesel supply line, roads and pipelines, and one Class 1 non-hazardous waste disposal well.

Oil processing at Alpine consists of 2 stages of 3-phase separation and a dehydrator to remove water to sales oil quality. Produced water is re-injected into injection wells at drillsite CD-1 (Colville Delta-1). Produced gas is compressed (through four stages) and flows into the gas injection header system. Gas is taken and mixed with indigenous natural gas liquids (NGLs) to form miscible injectant (MI). The MI is distributed to water-alternating-gas (WAG) injection wells at CD-1 and CD-2. Injection water consists of produced water and seawater from the Seawater Treatment Plant (STP).

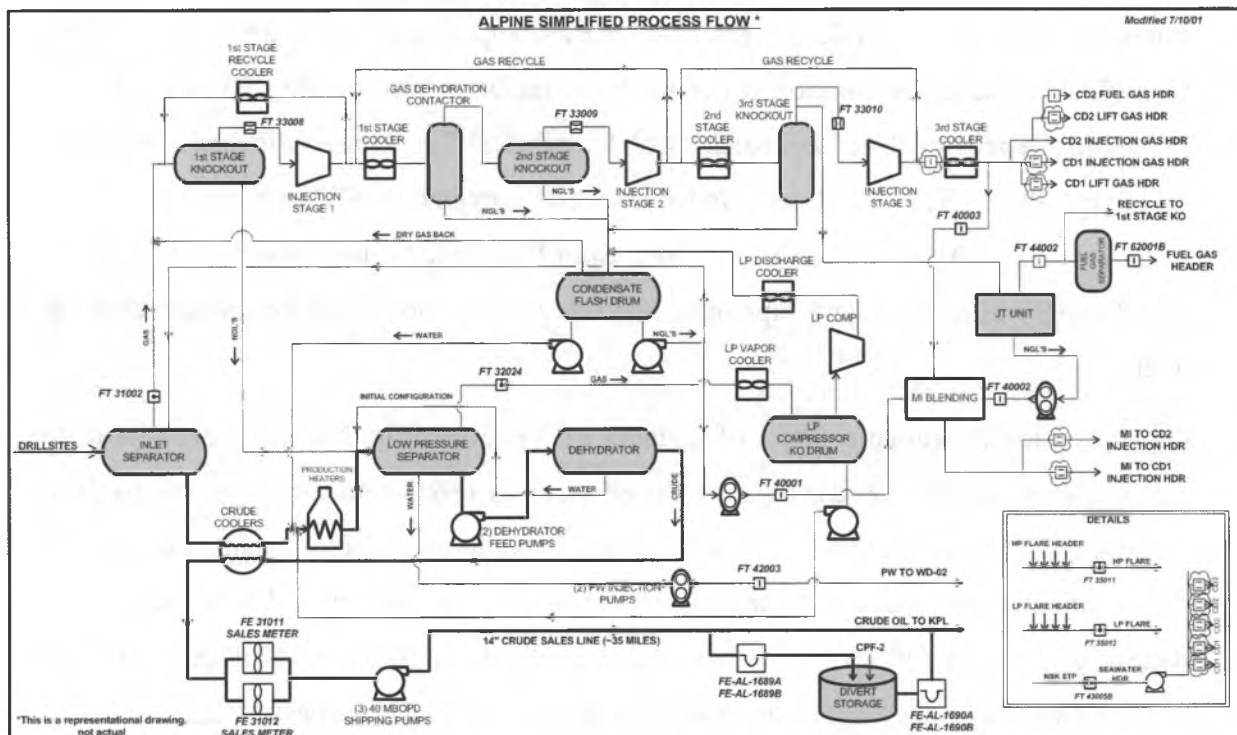
Table 1 depicts the 2003 production vs. original design capacity of the facility, along with the planned expansion capacity for late 2004 and 2005.

Table 1 Alpine Facility Operation vs. Capacity

Stream	2003 <u>Oper/design</u>	ACX-1 Design <u>Late '04</u>	ACX-2 <u>Design '05</u>	Units
Oil Production:	100,000/83,000	110,000	140,000	bopd
Gas Handling:	120/130	160	180	mmscfd
Water Handling:	4,000/10,000	100,000	100,000	bwpd
Water Injection:	80,000/80,000	140,000	140,000	bwpd

At this time, the Alpine Processing Facility has no spare capacity for new production. Alpine currently meets processing capacity for oil, gas, and water injection. Facilities expansions are planned for 2004 and 2005; however, it is likely that Alpine satellite development (Fjord, Nanuk, etc.) will offset most of the expanded capacity.

Figure 3 **Alpine Simplified Process Flow Diagram**



Badami

The Badami Field is currently in a warm shutdown. The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, and oil export facilities. A WAG injection and lift gas system are also in place at Badami.

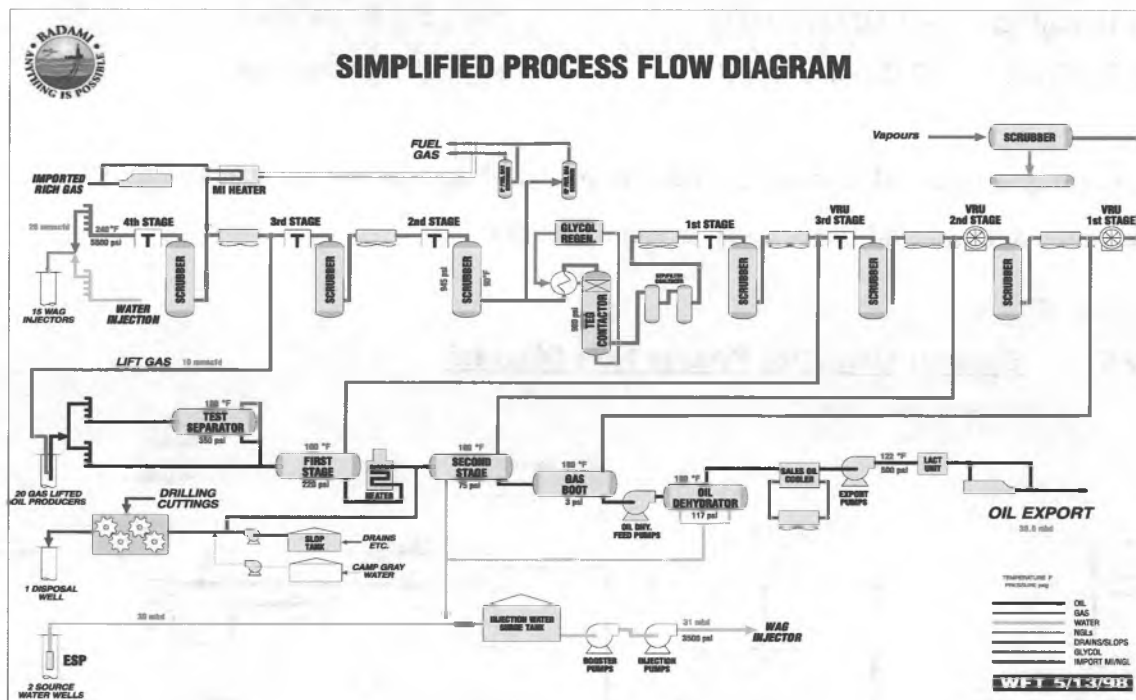
Access to the Badami facilities is by barge, ice road, rolligon, or air. Peripherals are an airstrip, a dock, a Class 1 non-hazardous waste disposal well, a grind-and-inject disposal well, and a source for electricity.

Table 2 **Badami Facility Operation vs. Capacity**

Stream	Operation/Capacity	Units
Oil Production:	0/35,000	bopd
Gas Handling:	0/25	mmscfd
Water Handling:	0/12,000	bwpd
Water Injection:	0/30,000	bwpd

Since Badami is in warm shutdown, there is theoretically space available up to the capacities shown. There may be additional costs associated with startup but there should not be any backout charges for processing here.

Figure 4 Badami Simplified Process Flow Diagram



Endicott

The Endicott facility consists of two man-made gravel islands located in the Beaufort Sea. Produced gas is separated from the crude oil and processed to remove NGLs. The NGL volumes are injected into the dry oil sales line subject to capacity available with existing pipeline vapor pressure specifications. NGLs not sold are blended to create a miscible injectant (MI) that is used in a water-alternating-gas enhanced oil recovery project. Any residual gas is reinjected into the reservoir to provide pressure support, used for fuel, or routed to the gas lift system to provide artificial lift. Produced water is treated before being reinjected into the reservoir. Seawater can also be treated before being injected.

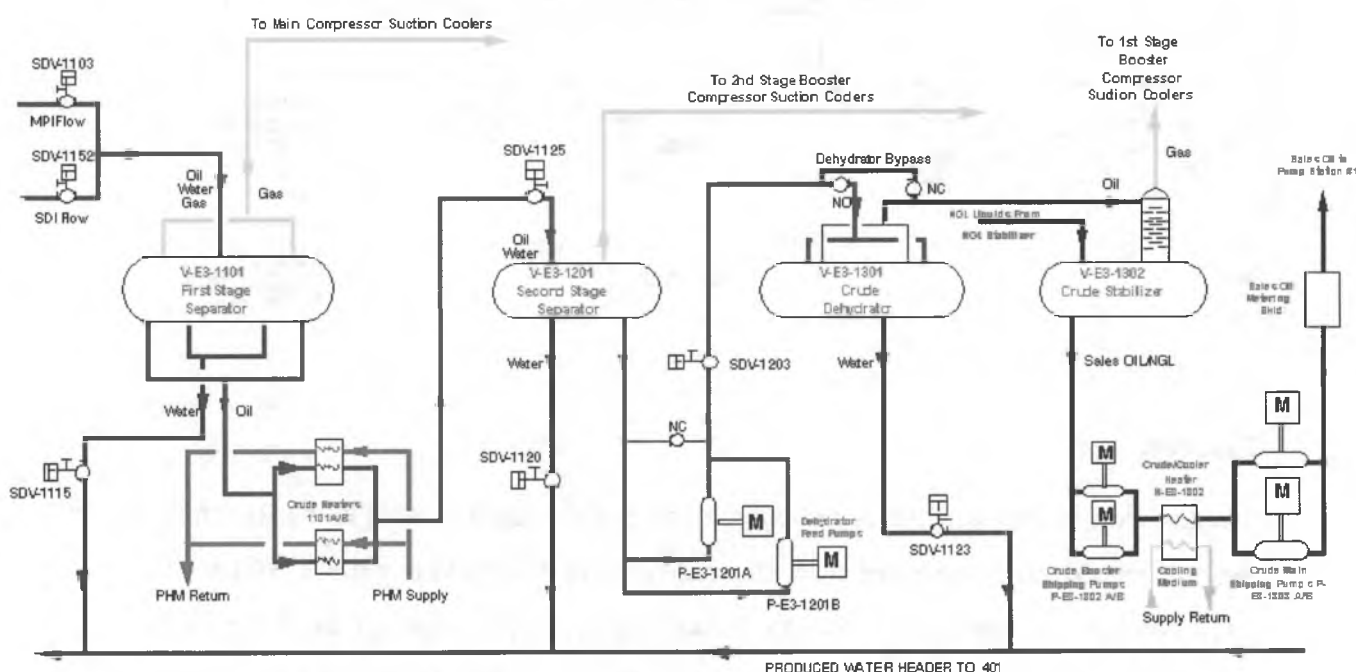
Endicott's two gravel islands are connected to each other, and linked to land by a gravel causeway.

Table3 Endicott Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~25,000/115,000	bopd
Gas Handling:	~455/455	mmscfd design
Water Handling:	~210,000/225,000	bwpd design estimate.
Water Injection	~245,000/245,000	bwpd design estimate.

There currently is spare oil capacity at Endicott, but water and gas are at capacity limits. Any new production would likely result in some backout.

Figure 5 Endicott Simplified Process Flow Diagram



Kuparuk

The Kuparuk facilities consist of three Central Processing Facilities (CPF).

The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, and oil export facilities. There is a seawater treatment plant designed to prepare seawater for waterflood operations.

Access to Kuparuk is by a gravel spine road. Other facilities include a construction camp, spill response center, industrial center, warehouse, airstrip, topping plant and

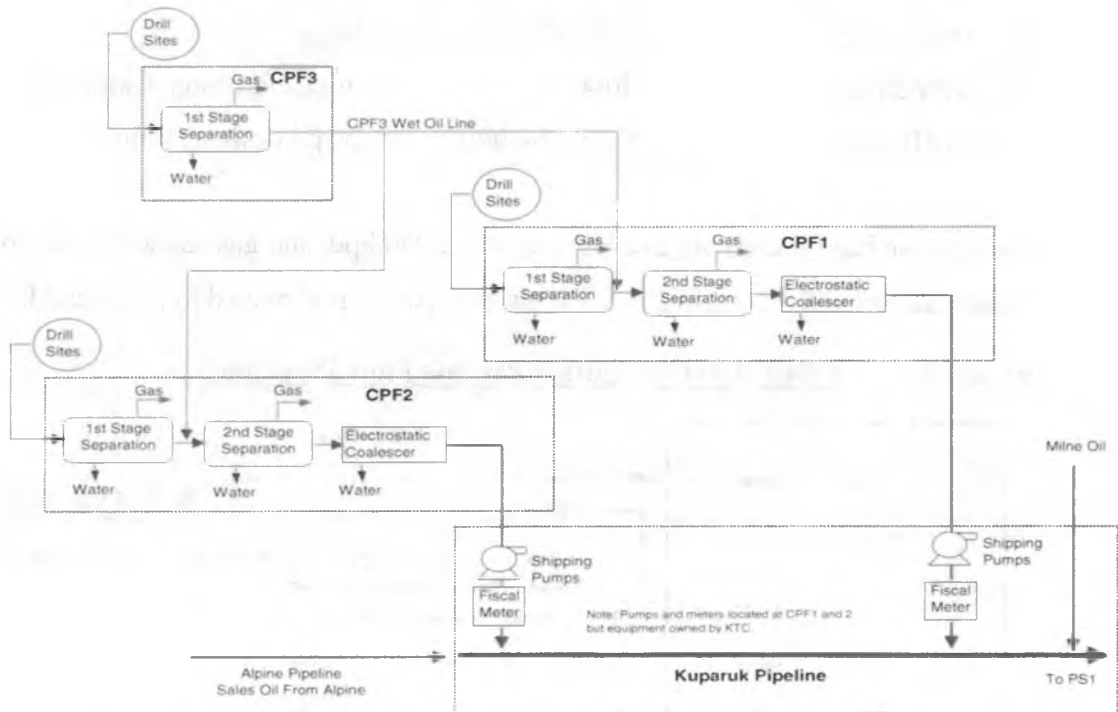
roads. There are four Class 2 non-hazardous waste disposal wells within the Kuparuk River Unit.

Table 4 **Kuparuk facilities Operation vs. Capacity**

Stream	CPF-1	CPF-2	CPF-3	Units
Oil Production	105,000/170,000	120,000/160,000	50,000/85,000	bopd
Gas Handling	200/200	260/260	150/150	mmscfd
Water Handling	250,000/250,000	250,000/250,000	100,000/125,000	bwpd
Water Injection	250,000/250,000	300,000/300,000	150,000/220,000	bwpd

There currently is spare oil capacity, but water, total liquid and gas production are at capacity limits. New production would result in backout.

Figure 6 **Kuparuk Simplified Process Flow Diagram**



Milne Point

The Milne Point Unit consists of a Central Facility Plant (CFP) and 12 producing / injecting well pads. The production facility is designed to separate oil, gas and water. After the gas is produced, it is compressed for gas injection and gas lift in the reservoir. After processing, all of the produced water is injected into the reservoir. Artificial lift at the Milne Point Field is a mix of ESPs, jet pumps and some gas lift, with ESPs being the most prevalent. Two pipelines transport liquids to and from Milne Pt. (NGL northbound, and oil southbound).

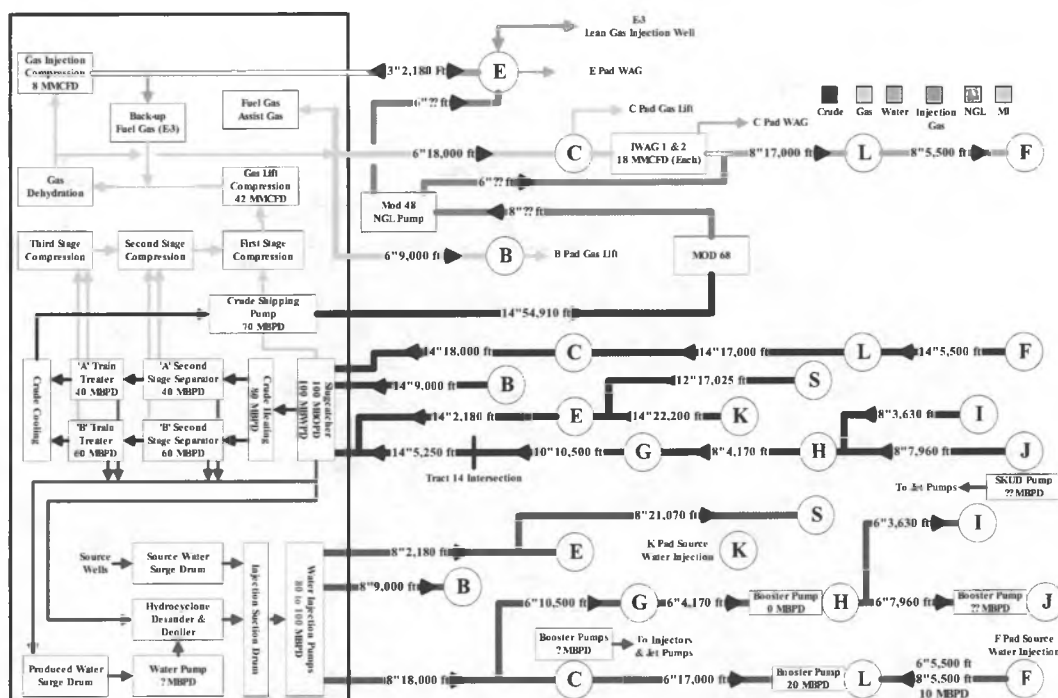
A permanent camp facility for up to 306 personnel is available. MPU currently utilizes ~40% of the space most of the time (~110 personnel). Transportation to and from Milne is by gravel road.

Table 5 Milne Point Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~58,000/75,000	bopd
Gas Handling:	~40/42	mmscfd design estimate.
Water Handling:	~47,000/80,000	bwpd design estimate.

Milne Point has oil capacity available up to 12,000 bpd, and gas capacity available up to 2 mmscfd through 2015. In 2011, the water capacity is expected to be reached.

Figure 7 Milne Point Simplified Process Flow Diagram



Northstar

The Northstar facilities are on Seal Island, located 6 miles offshore of the Point Storkerson area in the Alaskan Beaufort Sea. Seal Island is a gravel island of approximately 5 acres. Two pipelines transport hydrocarbons to and from the Northstar Unit. The pipelines include one 10-inch common carrier pipeline from Seal Island to Pump Station No. 1 to transport the sales oil to TAPS. The second 10-inch pipeline is to import gas from the Central Gas Facility in the Prudhoe Bay Unit. The production facility is designed to separate oil, gas and water. Produced water is processed and disposed of into a Class 1 waste disposal well (there are two on the island). Following dehydration and NGL removal, produced gas is injected into the reservoir. Sales oil is cooled to Northstar export pipeline specification and shipped to TAPS. At the Pump Station No. 1 end of the export line, the sales oil is re-heated to TAPS specifications.

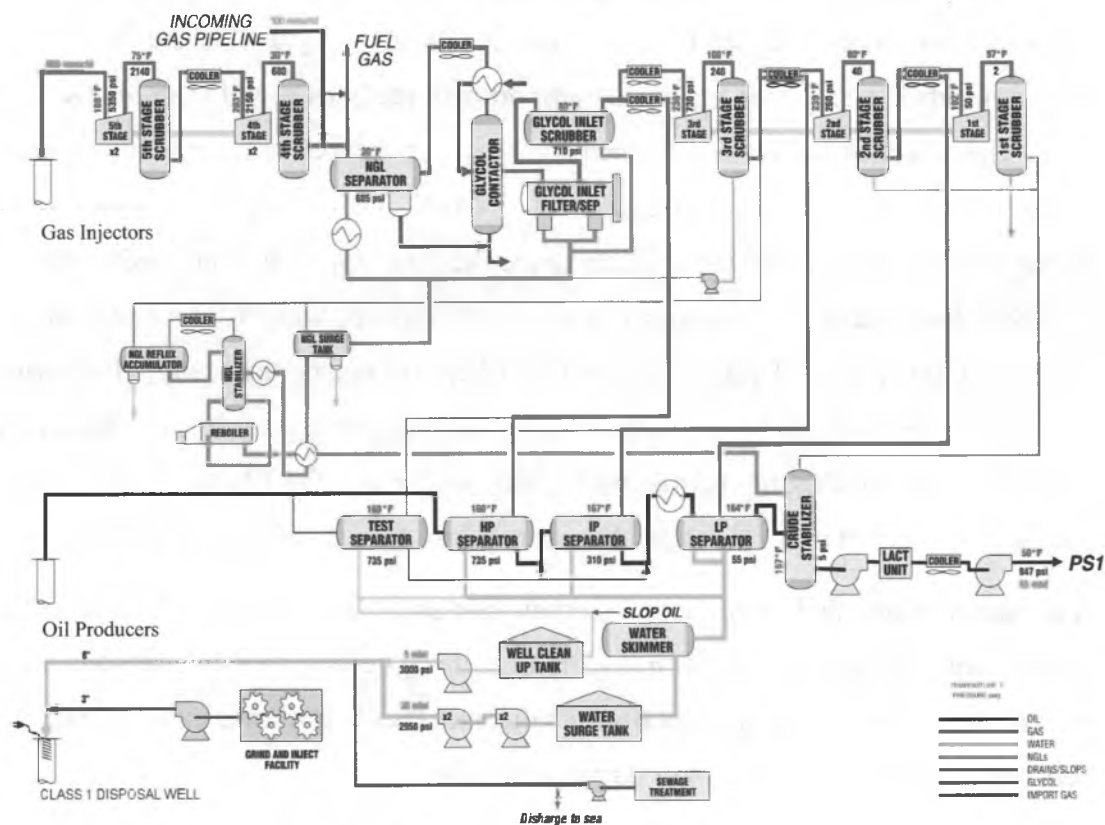
A permanent camp facility for up to 74 production and drilling personnel is also installed on the island. Multiple modes of transport are utilized depending on the season: an ice road during winter; barge, hovercraft and helicopter transport during summer; and helicopter and hovercraft transport during broken ice.

Table 6 Northstar Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~65,000/77,000	bopd
Gas Handling:	~410/500-555	mmscfd design estimate.
Water Handling:	~7,500/30,000	bwpd design estimate.
Combined Water and Oil limit	~70,000/85,000	bfpd design estimate

Northstar will have capacity available in oil and water handling but is expected to reach gas capacity by 2006.

Figure 8 Northstar Simplified Process Flow Diagram



Point McIntyre/Lisburne

The Lisburne Production Center (LPC) consists of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, NGL production facilities, and oil export facilities. The LPC also generates electric power.

The Pt. Mac/Lisburne facility has no camp. It houses personnel at the nearby Prudhoe Bay Main Construction Camp. Access to and from Point McIntyre/Lisburne is by gravel roads.

Table 7 Pt. McIntyre/Lisburne Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~60,000/205,000	bopd
Gas Handling:	~375/470	mmscfd design
Water Handling:	~140,000/160,000	bwpd design estimate

The facility is currently at or near both gas and water capacity. New production would result in some backout.

Prudhoe Bay

The Prudhoe Bay facilities, the largest on the slope, consist of six separate major production processing centers with a central power station, central gas processing facility, central compressor (injection) facility, two operating centers, a central seawater treatment plant, a topping plant, and a plant to grind and inject drill cuttings. There is one grind-and-inject well, and three Class 2 non-hazardous waste disposal wells. The production facilities consist of multi-stage oil/water/gas separation, water injection, gas treatment, compression and injection, NGL production and oil export.

The main housing facilities for the Prudhoe Bay Field are the Eastern Operating Camp (EOC), the Western Operating Area Camp (BOC), and the Main Construction Camp (MCC). In addition to these, there are a number of support camps throughout the field. The PBU area can accommodate up to 963 people. (This figure does not include accommodations in Dead Horse.)

Table 8 Prudhoe Bay Facility Operation vs. Capacity

Stream	Operation/Capacity	Units
Oil Production:	~487,000/1,660,000	bopd
Gas Handling:	~8,700/8,700	mmscfd design estimate.
Water Handling:	~1,720,000/1,720,000	bwpd design.

There is room for oil, but gas production is at capacity limits and water handling is at or approaching capacity limits in all facilities. New production would result in some backout.

Projected Production and Pipeline Constraints/ Excesses

The following describes current and forecasted oil production for North Slope facilities. These numbers are for trend and probable outcomes and should not be taken as exact. The information was provided by the producers, with the exception of Endicott, Lisburne and Prudhoe, which were taken from the State of Alaska 2003 Revenue Source Book. Any new permits or emissions restrictions have not been addressed in this report. These rates are used for forecasting the pipeline usage. Also shown on the first row of the table are current pipeline capacities.

Table 9 North Slope Pipeline Capacities and Projected Field Production

MBPD	Badami	Endicott	Milne Pt.	Alpine	Kuparuk	NorthStar	TAPS
<u>Year</u>	<u>Pipeline</u>	<u>Pipeline</u>	<u>Pipeline</u>	<u>Pipeline</u>	<u>Pipeline</u>	<u>Pipeline</u>	<u>Pipeline</u>
Current Capacity	35	100	65	100	400	65	1400
2003	0	29	51	98	361	62	994
2004	0	30	52	99	359	68	997
2005	0	29	53	98	364	60	982
2006	0	27	57	103	376	50	968
2007	0	25	58	117	390	40	954
2008	0	24	59	117	379	32	923
2009	0	22	59	104	367	27	878
2010	35	56	59	86	338	20	852
2011	50	70	58	71	322	17	824
2012	48	66	57	60	300	15	775
2013	38	55	56	51	290	12	734
2014	31	47	56	44	273	10	691
2015	27	42	55	38	267	9	663

(a) Badami includes projected Liberty throughput

(b) Endicott includes Badami and Liberty throughput

(c) Kuparuk includes Alpine and Milne Pt. throughput

Before entering the oil and gas exploration and development business, a potential producer should consider the process required to transport hydrocarbons from the North Slope to market. Currently there are three market options for North Slope production: sales at the production facility, sales in Alaska, and sales on the West Coast. Sales at the production facility trigger no transportation issues for the producer, as the custody

transfer is at the outlet flange of the facility. The other two options will entail the use of one or more of the Common Carrier Pipelines in Alaska. These pipelines are regulated by State and Federal Commissions. These pipelines will not discriminate between shippers, but will prorate volumes if pipeline capacity is exceeded. Crude oil product must meet certain specifications to be accepted by the pipeline.

The pipeline specifications for the oil delivery to PS1 are as follows:

- Maximum basic sediment and water (BS&W) content of 0.35%
- Minimum delivery temperature of 105° F to prevent paraffin deposition
- Maximum delivery temperature of 142° F
- Maximum True Vapor Pressure of 14.2 psia

The existing TAPS system can handle more than 1.4 million barrels of oil a day.

Alyeska Pipeline Services Company is currently evaluating a plan to redesign TAPS to transport approximately 1 million bpd, expandable up to about 1.14 million bpd with drag reducing agent.

These are only guidelines for capacity since the addition of drag reducing agent and operational variation can change the overall capacity. If the amount of production exceeds the capacity, the pipeline operators will reduce each producer's rate on a prorated basis until capacity is met. Therefore, new production going into a pipeline that is at capacity will cause a reduction in existing production so that all producers can ship their product. This production will not increase or decrease the total quantity, just redistribute the production allocated to each producer.

Each pipeline has a group of owners that will transport fluids for a per barrel charge (tariff). Transportation must be coordinated from point of production to market and may involve several pipelines and different shippers. TAPS will transport the product to the Port of Valdez. The product must be tanker transported from Valdez to the interstate market.

Figure 9 is a map of the North Slope pipelines and TAPS. Figures 10 - 16 are timelines of the pipeline capacity and potential excess shipping space. These figures are based on production profiles as shown in the State of Alaska 2003 Revenue Book and on information provided by producers.

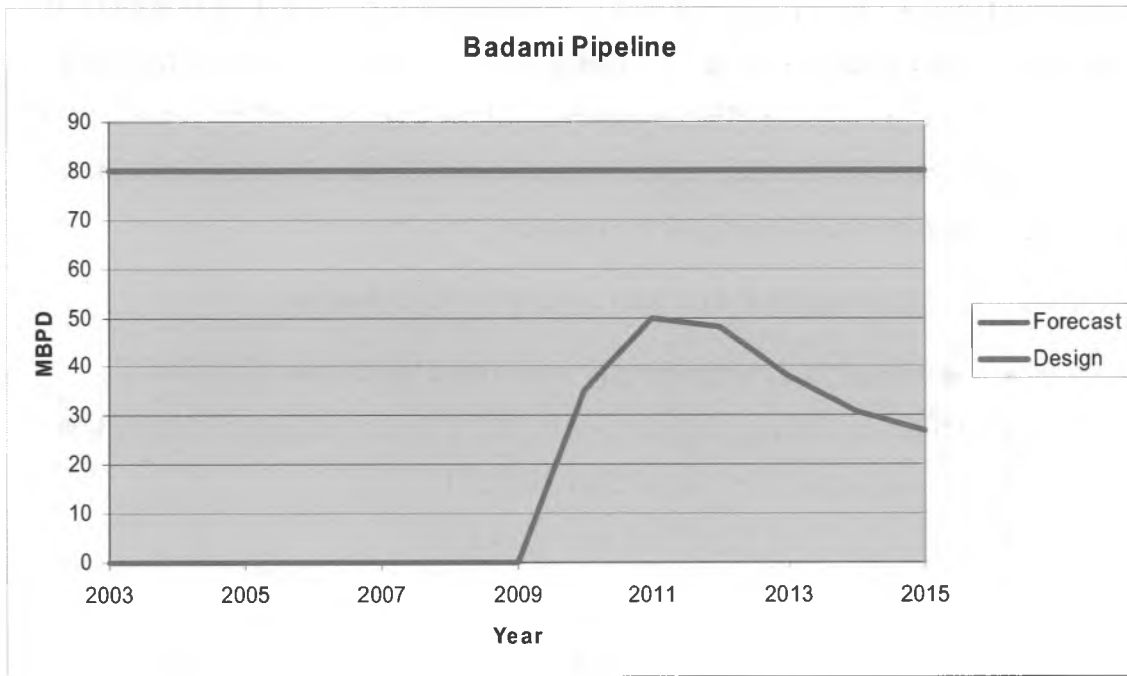


Figure 10

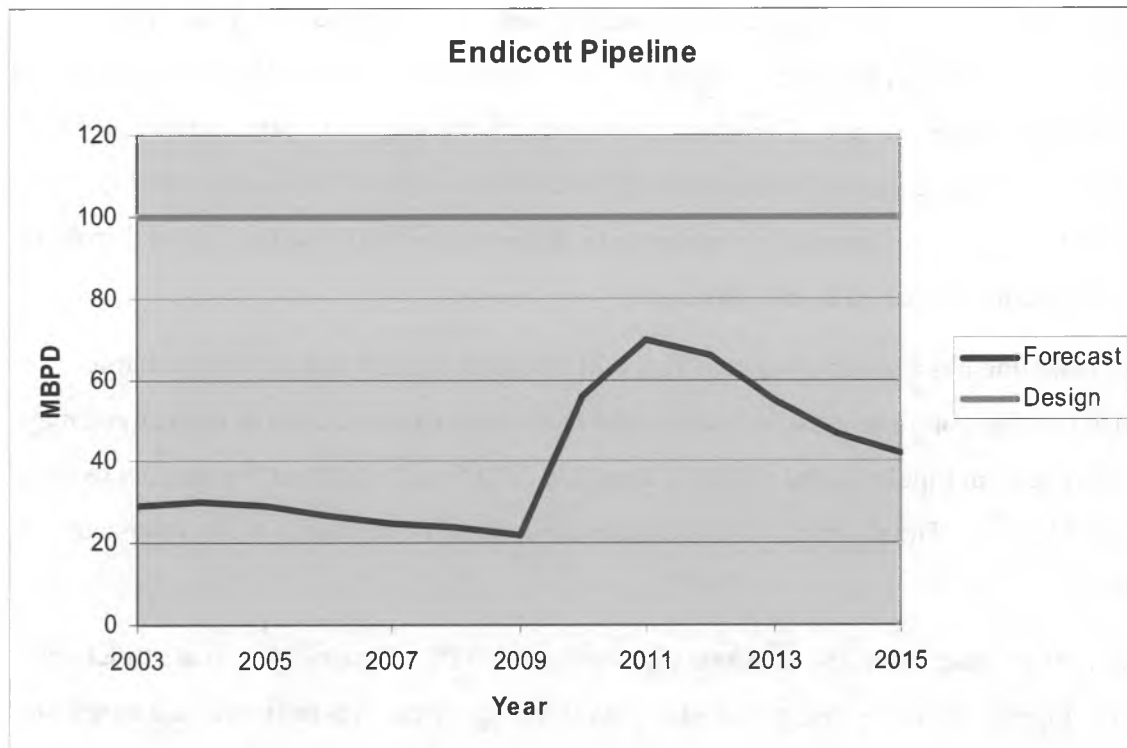


Figure 11

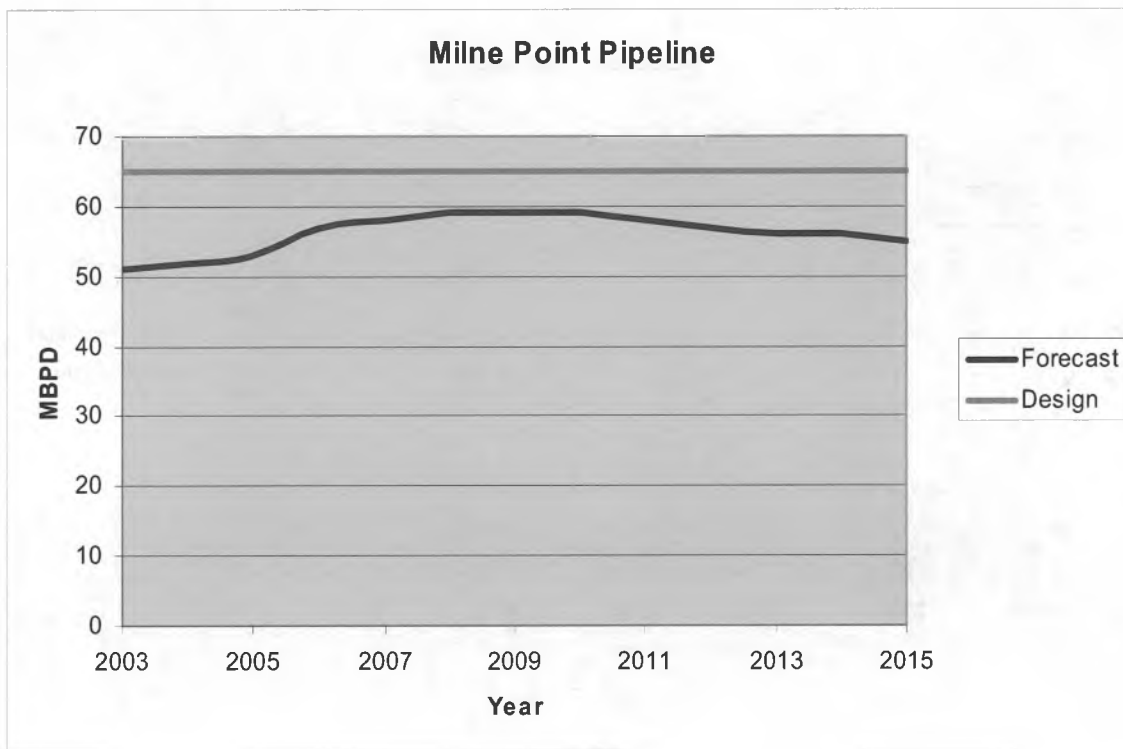


Figure 12

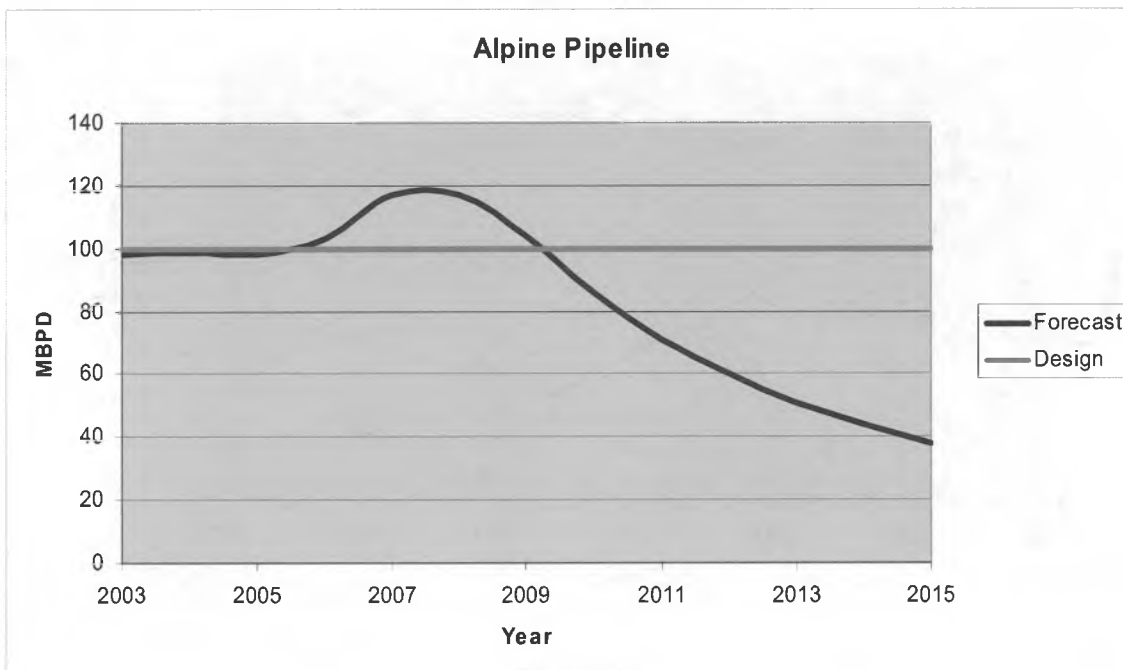


Figure 13

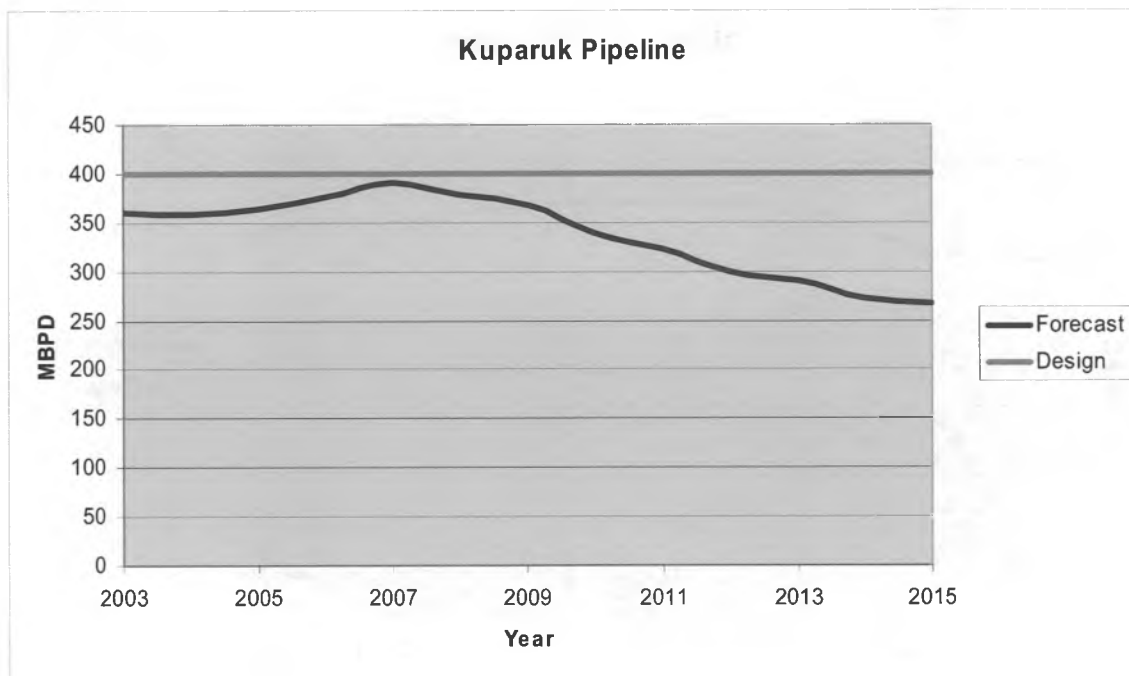


Figure 14

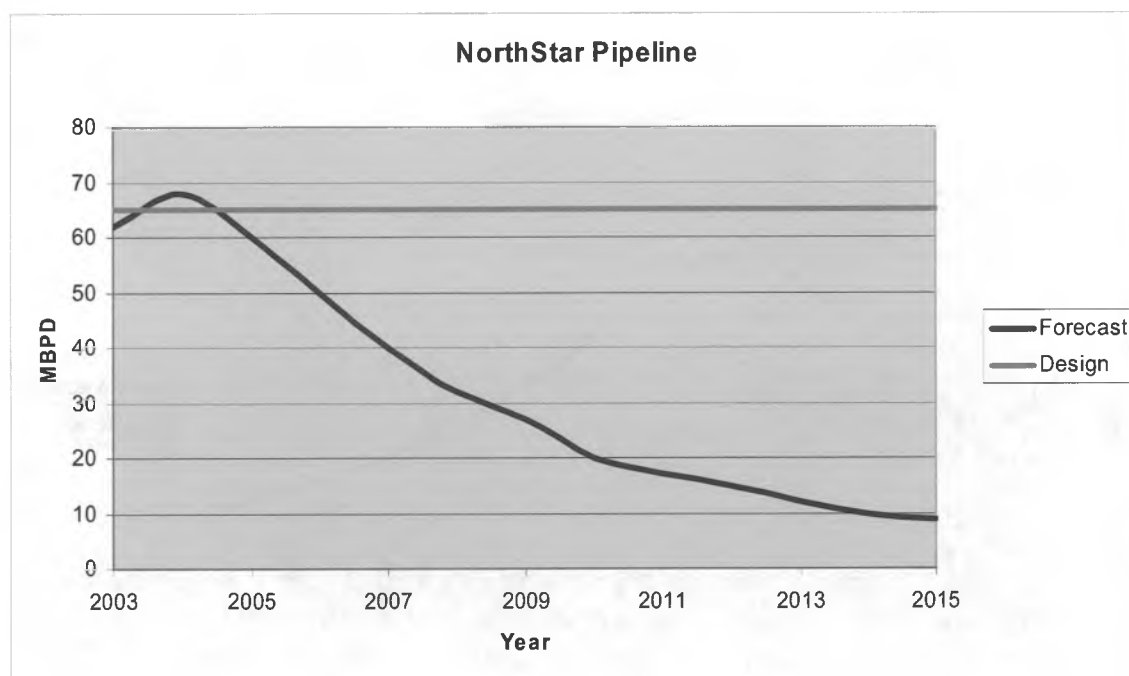


Figure 15

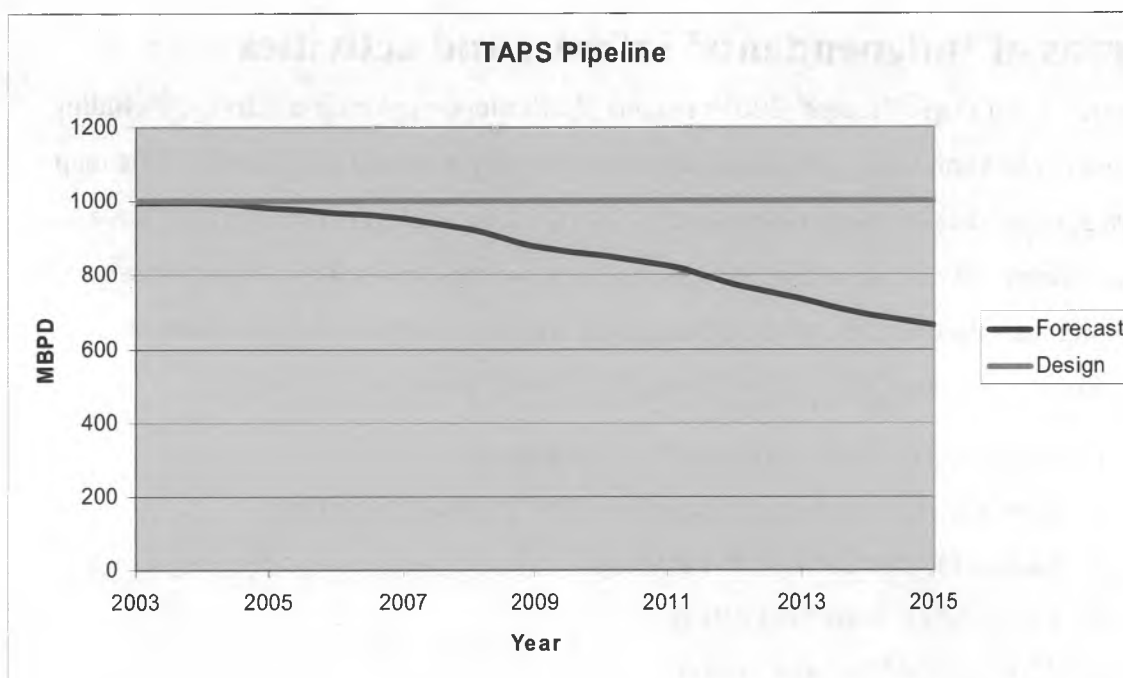


Figure 16

Table 10 illustrates the processing streams for which excess capacity is available, which streams are constrained, whether a backout calculation is likely, and status of pipeline capacity for each of the North Slope fields.

Table 10 Facility and Pipeline Capacity/Constraint Summary

<u>Facility</u>	<u>Capacity Available for:</u>	<u>Constrained Stream</u>	<u>Backout</u>	<u>Pipeline</u>
Alpine	none	oil, gas, water	likely	Full
Badami	oil, gas, water	none	not likely	Not Full
Endicott	oil	gas, water	likely	Not Full
Kuparuk	oil	gas, water	likely	Near Full
Milne Point	oil, gas, water	water 2011	maybe	*
Northstar	oil, gas, water	gas 2006	maybe	Near Full
Pt. Mac/Lis	oil, water,	gas	likely	Near Full
Prudhoe Bay	oil	gas, water	Certain	Not Full

- Feeds into Kuparuk Pipeline and dependent upon space there.

Areas of Independents' interest and activities

Figure 17 is a map of recent (2001-present) North Slope exploration activity, including recent exploration wells, unit boundaries, and recently acquired state leases. This map portrays the areas of interest expressed by North Slope explorers through their lease acquisitions and drilling activities, and indicates the areas most likely to put pressure on existing infrastructure. Some of the activities which, given successful exploration programs, will potentially impact the facility sharing landscape include:

1. Pioneer/Armstrong Oooguruk Unit evaluation
2. Kerr-McGee/Armstrong Nikaitchuq 2004 Exploration drilling
3. ConocoPhillips 2004 NPRA drilling
4. Pioneer 2004 lease acquisition
5. AVCG 2004 lease acquisition
6. Ultrastar 2004 lease acquisition

Pioneer and Armstrong partnered in 2003 to drill 3 exploration wells in the Oooguruk Unit northwest of KRU (yellow leases). They have announced a discovery in the Nuiqsut Fm., and are evaluating options for development of this discovery. This potential development could impact KRU facilities and/or the Kuparuk Pipeline.

Kerr-McGee and Armstrong drilled two wells (Nikaitchuq #1&2) northwest of MPU in 2004, and have announced a discovery in the Sag River Fm. Potential development here could impact MPU facilities, the Milne Point Pipeline, and the Kuparuk Pipeline.

ConocoPhillips has drilled a number of discovery wells to the west of CRU, all of which figure to impact the Alpine facilities, Alpine Pipeline, and Kuparuk Pipeline.

Pioneer acquired tracts in the 2003 North Slope and Beaufort Sea Areawide Lease Sales in the Hemi Springs area, as well as north of PBU, east of Northstar, and west of Kuparuk. Successful exploration programs associated with these lease acquisition could impact numerous production facilities.

AVCG added to their lease position in 2003 with acquisitions east and south of CRU, north of PBU, and west of KRU. They are considering stand-alone processing

options at this time, which would limit the facility impact to common carrier pipelines.

UltraStar Exploration added new leases to their portfolio in 2003 around Badami, and north of PBU, and successful drilling of their prospects could impact Badami, Pt. McIntyre/Lisburne and/or PBU facilities.

Most of the activity shown on the map is focused around existing facilities, with the exception of SWEPI and Unocal's lease acquisitions some 50 miles south of KRU, and Total's drilling nearly 50 miles west of CRU.

A critical constraint will be available processing and pipeline capacity to the west and north of KRU. Alpine satellites, NPRA, and the Ooooguruk and Nikaitchuq discoveries will all place significant pressure on the Kuparuk and Alpine pipelines. However, with enough new production potential realized, additional pipeline capacity may be justified.

Facility Sharing Negotiation Specifics

Guideline for Negotiation Strategy Template

PRA has put together a guideline for a facility sharing agreement based largely on Ballot No. 255 for Kuparuk. This guideline deals with the technical and accounting aspects and not the legal provisions of an agreement. All parties are advised to obtain legal counsel to protect their rights and limit their liabilities.

This guideline's purpose is to illustrate the anticipated components of a possible agreement and the expected ranges of costs associated with key components. It is not intended to be all inclusive. Every actual agreement will have its own particulars and be specific to that situation. The key to an agreement is to establish fair terms for utilizing existing infrastructure that provide third party owner(s) improved economics to develop and produce from nearby fields or other commercial paying reservoirs while compensating infrastructure owners for their existing investment, risk taking and operations. The facility owners have incurred substantial risk and invested large capital in their facilities. The third party owners can benefit from avoiding construction time,

permits (possibly) and risk of delays by using existing facilities. All parties can benefit by increased production and operations.

Any specific numbers in this guideline are for illustrative purposes and indicate possible ranges and are not intended to be fixed or binding on any party.

Facility Sharing Agreements Should Include the following provisions:

1. Identification of Facility Owners

This provision identifies the facility owners and their intentions.

2. Identification of Third Party Owners

This provision identifies the third party owners and their intentions.

3. Definitions of Terms

This provision defines terms of substance to this agreement for clarity.

4. Definition of Facilities

This provision defines facilities that are and are not included in this agreement.

5. Definition of Third Party Facilities

This provision defines facilities that are third party sole responsibility.

6. Standards of Produced Fluids

This provision defines fluid compatibility and physical limitations.

7. Priorities Governing Production Processing

This section states that the facility sharing agreement will maximize the total oil production. It sets priorities and defines impacts of operations. In order to maximize oil production, high GOR, high WOR wells will be curtailed first regardless of ownership. Wells of the facility owner could be shut-in or curtailed, thereby decreasing the facility owner's total production. The volume not produced by the facilities owners is "backed out" to make room for the third party production. To compensate the owners for this backout, the backout volume is calculated via a process described in more detail later in this report, and transferred to the facility owners from the third party owners. This backout volume is used to adjust the fee-appropriate volumes for the third. In other

words, the third party owners do not pay fees on the barrels they must give up as backout compensation

8. Produced Water and Seawater

Facility owners will provide to each third party a volume of water, for water injection, that is equal to the volume of water delivered to the facilities by the third party production facilities.

9. Excess Water Volumes

To the extent that additional produced water or seawater volumes are available and desired, facility owners will provide third party facilities with water volumes in excess of their water production where needed to maximize and optimize field development. A fee may apply for this excess volume.

10. Facility Access Fees

The facility owners will be compensated for their investment and ongoing costs incurred to provide facilities and processing of the third party fluids.

Capital Access Fee

This fee compensates the facility owners on an adjusted per barrel processed basis for their past capital investment. This fee recognizes that the facility owners have invested large sums in the past for the equipment and facilities that are available to the third party. Generally this fee would have a depreciation component and a rate of return component.

Capital Access Fee Surcharge

This fee compensates the facility owners for capital costs incurred after third party processing begins. This would apply if the third party did not participate in a joint capital project but the third party benefits from the project. This fee could be a per barrel charge and apply in capital increments. For example: a capital access fee of \$0.025 per barrel imposed following each \$25 million increment of cumulative gross amounts expended on joint capital projects and excess routine field CAPEX.

Abandonment Fee

This fee compensates facility owners for future abandonment costs that will be incurred during the abandonment of the facilities.

Abandonment Fee Surcharge

This fee is to cover abandonment costs for capital added after third party processing begins.

11. Accounting

For purposes of determining volumes of third party oil processed through facility equipment, the volumes specified in the monthly production and injection reports filed with the Alaska Oil and Gas Conservation Commission will be used less any adjustments caused by backout. Allocation among the owners will be determined by the parties.

12. Operating and Maintenance Costs

The facility owners incur operating and maintenance costs for all of the facilities and drillsites. The costs for any facilities not benefiting the third party facilities or production shall be excluded from the calculations.

Plant Liquid Processing Fee

The per-barrel fee shall be determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross liquid processing operations but do not include any O&M costs not benefiting the gross liquid processing operations.

Plant Gas Processing Fee

The per-mcf fee shall be determined by dividing the O&M costs by the volume of total gas production and lift gas processed in the facilities. The O&M costs can include total plant labor, direct operating costs and allocated field support costs which are attributed to gross gas processing operations but not include any O&M costs not benefiting the gross gas processing operations. The fee shall be applied to the allocated volume of fuel gas, flare gas, take-in-kind, shrinkage and lost gas attributable to third party fluids.

Common Drillsite

The per barrel fee shall be determined by dividing the O&M costs by the volume of total liquid production (oil plus water) processed in the facilities. The O&M costs can include total drillsite labor, direct operating costs and allocated field support costs which are

attributed to all drillsite operations but shall exclude charges for operations which do not benefit the third party production. The fee shall be applied to third party gross liquid production (oil plus water) processed through the facilities less any adjustments.

Water Fee

The per-barrel fee shall be determined by dividing the O&M costs by the total make-up water volume made available and used for injection in all reservoirs. The O&M costs can include total labor, direct operating costs and allocated field support costs which are attributed to seawater treatment plant operations and associated pipelines which carry seawater to the injection plants. This fee shall be applied to each barrel of make-up water injected into the third party reservoir.

Ad Valorem Tax Fee

The annual ad valorem taxes chargeable to the third party shall be determined by multiplying the total annual ad valorem taxes by the third party adjusted gross liquid production (oil plus water) processed in the facilities divided by the total liquid production (oil plus water) processed in the facilities.

13. Accounting

The fees for liquid and drillsite shall be applied to third party's gross liquid production (oil plus water) processed through the facilities less any adjustments.

14. Fluids Associated with Backout Oil

The adjusted backout volumes have an associated volume of water and gas. These volumes of water shall be the gross third party water production times the adjusted third party backout volume divided by the gross third party oil production. The gross third party gas production times the adjusted third party backout volume divided by the gross third party oil production is the associated gas volume.

15. Determination of Costs and Volumes

The costs shall be based on the actual booked costs and actual volumes of fluids processed. The third party volumes shall be those specified in the production and injection reports filed by the operator with the Alaska Oil and Gas Conservation Commission.

16. Routine Field Capex Share

Routine field CAPEX shall be allocated to the third party owners on third party's gross liquid production (oil plus water) processed through the facilities less any adjustments divided by the total liquid production processed through the facilities.

17. Joint Capital Projects

A joint capital project may be proposed by either the facility owners or the third party owners. The percentage voting and procedure for proposing the projects can be negotiated by the parties and set forth in this agreement. All construction and modifications shall be owned solely by the facility owners.

18. Volume Adjustments

Backout

There will be a volume adjustment to reflect a backout of production from the facility owners' production caused by the introduction of third party production. This volume would be further adjusted to account for quality, royalty, and tax. **See separate write up on Backout Methodology Guidelines.** This adjustment will transfer the processing fees to the receiving party for the backout volumes.

Quality

The differences in the characteristics of the oil production from the facilities and the oil production from the third parties will be recognized and compensated with a quality adjustment. These differences could be caused by API gravity differences, compositional differences and impurities. The compensation will be a transfer of barrels between the parties. The exact procedure and calculation would be negotiable after the determination of the Quality effect. A quality adjustment factor (QAF) will need to be established for each stream and agreed to by the parties. The QAF volume is equal to the gross oil production for the stream (adjusted for royalty and tax) times the QAF for the stream minus the QAF average divided by the QAF average. The QAF average is the total of each stream's gross oil production times its QAF divided by the sum of the gross oil production for all streams. If the resulting QAF volume is positive, the stream will receive barrels, if negative, the stream will deliver barrels. The methodology can be

simple, such as based on API gravity ratios, or can be more complex, such as based on component value.

Tax and Royalty

Backout is considered a financial transaction; thus the value of the backed out oil is transferred to the receiving party while the delivering party retains the reserves for booking purposes and payment of royalties and severance taxes. To calculate the net backout share allocated to each party, the backout volume is adjusted for severance tax and royalty to keep the receiving parties whole on an after severance tax and royalty basis. The net backout volume will equal the backout volume calculated using a processing facility dynamic model, times one minus the royalty, times one minus the ELF, times the severance tax rate.

$$\text{Adj.BO} = \text{BO} \{1 - \text{Royalty}\} \times \{1 - \text{ELF}\} \times \{\text{SEVTAX}\}.$$

For example: If 100 barrels is the calculated backout volume, the adjusted volume would be: first, 100 times (1-.125 Royalty) equals 87.5 barrels; second, 87.5 times (1- (0.15 severance tax rate times .9 ELF)) equals 75.68 barrels. This way the delivering party pays the Royalty and Tax and the receiving party gets the barrels royalty and Tax free.

Allocation and Metering

Third party owners shall pay for all metering investments required for processing their fluids. Facility operator will prepare and maintain all information necessary for the filing of any reports required by governmental regulatory authorities relating to volume, quality, and disposition of produced fluids.

The unit operator will conduct well tests or metering as required for the allocation of production and provide information to all parties. This information will be that necessary for the third party to file any reports required by government regulatory authorities relating to volume, quality, and disposition of produced fluids.

19. Gas Supply

Each third party owner shall be obligated to supply gas to satisfy gas consumed during third party operations and utilized in the facilities for processing the third party production. Third party owners shall be responsible for fuel gas consumed by its equipment and a proportionate share of the fuel gas used in the facilities.

20. Gas Use and Reinjection

Any gas not used and consumed shall be taken in kind, reinjected into the third party reservoir or injected into the facility owners' (FO) reservoir. The gas injected into the FO reservoir will be considered indigenous to the FO reservoir and no compensation for the gas will be given.

21. Warehouse Sharing

The third party facilities will be permitted to use facility materials for a percentage each year. The exact material and costs will be negotiated.

22. Legal and Accounting Rights

The agreement would have several provisions maintaining each party's various legal rights, indemnity and auditing procedures.

Example of Potential Costs

Although each case will have its own specifics, as an example of potential costs, a third party would expect to pay fees for KRU such as those shown below:

Table 11 Example of potential costs

Fee	Typical range	Per
Capital Access	\$1.00-1.80	BBL Oil
Abandonment	\$0.10-0.20	BBL Oil
Plant Liquid	\$0.09-0.15	BBL Liq.
Plant Gas	\$0.03-0.6	MCF
Drill Site	\$0.11-0.15	BBL Liq.
Excess Water	\$0.04-0.07	BBL Ex.Wtr.
Ad Valorem	\$0.10-0.16	BBL Liq.

Possible ranges of Backout:

Backout could range from as low as 2% to as high as 50%. The PBU satellites range from 2% to 6%. The KRU satellites range from 3% to 30% with an average of 9%.

Backout Methodology Guidelines

The following procedures are guidelines for a hypothetical methodology for determining the impact of backout fluids in facility sharing agreements. It is not intended to be all inclusive and areas may be subject to negotiation for a specific agreement. Kuparuk Ballot 255A is generally followed as this guideline. This methodology is detailed, complex and heavily dependent on a detailed dynamic plant model. Presently, only the KRU and PBU facilities have such a model in place. Other facilities would have to develop such a model, make use of existing less sophisticated models or negotiate a method for determination of backout volumes. See Backout Methodology Alternatives Section.

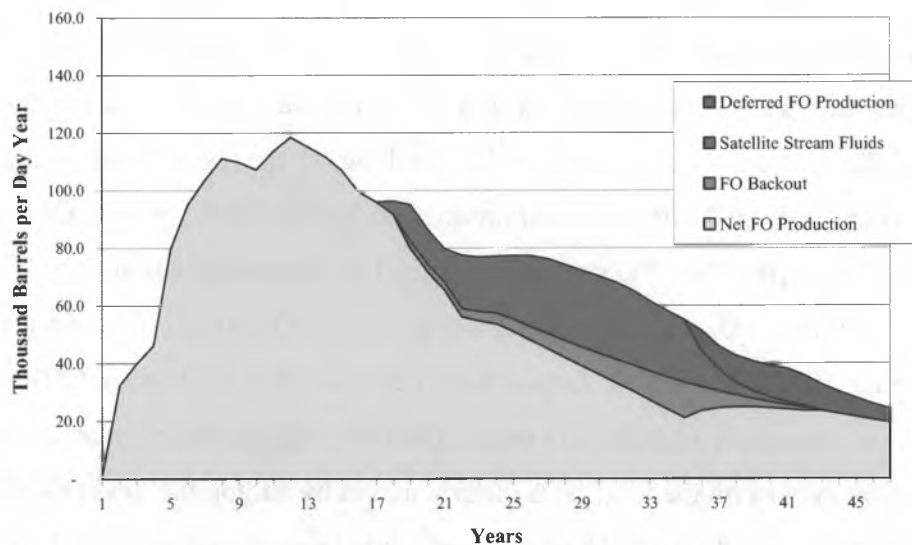
The owners of the existing processing facilities shall be designated as “FO” and the owners of the stream of fluids to be introduced into the facilities shall be designated as “SO”. The term backout fluid means that volume of FO oil that will be deferred due to the limitations of the facilities if the SO fluids are processed.

The concept of backout is real, and it represents actual deferred or lost production, resulting in measurable loss of revenue to the facility owner. Backout only exists when the facilities are constrained in some manner, causing the combined streams to be larger than the capacity of the facilities. This is remedied by backing off the less efficient wells, such as those with high GOR or WOR, in lieu of production from lower GOR or WOR wells. In a simplified example, if the FO stream generates 100 mmscfd of gas and the facilities can handle 120 mmscfd, while the SO stream generates 30 mmscfd, then the gas handling is the limiting factor. For efficient operation of the facilities, the highest GOR wells would be backed out, likely from the FO wells, thus reducing the overall production for the FO but actually increasing the total sales oil production by adding the lower GOR SO oil. This reduction in FO oil is called backout, and the FO must be compensated for their lost or deferred production. This reduction volume is theoretically deferred until production in the far future. The effect of this time delay in production is financial and physical. The wells may not produce as efficiently when returned to service, the prices of oil will be different, today’s value of the barrel will be discounted by the time delay of production and the facilities may be uneconomical to operate thereby not recovering all

of the barrels. These situations are not easy to define, and an overall modification factor can be negotiated to account for variance in these unknowns.

Figure 18 illustrates the impacts of backout on the production profile. Hypothetical facility owner (FO) production in thousands of barrels per day is shown in light blue. Satellite stream (SO) operator production (dark blue) begins in year 18 and is accompanied initially by modest rates of backout (grey). Over time backout increases as satellite stream fluids GOR increases, in this example to a peak of about 35% of FO gross production. Eventually satellite production ramps down and shuts in. In period 36, toward the end of field life, FO deferred production is re-established (magenta). In this illustration FO deferred production is less than cumulative backout, indicating that a portion of cumulative backout is not recovered. Thus, in addition to lost time value of money, FOs forego production due to backout.

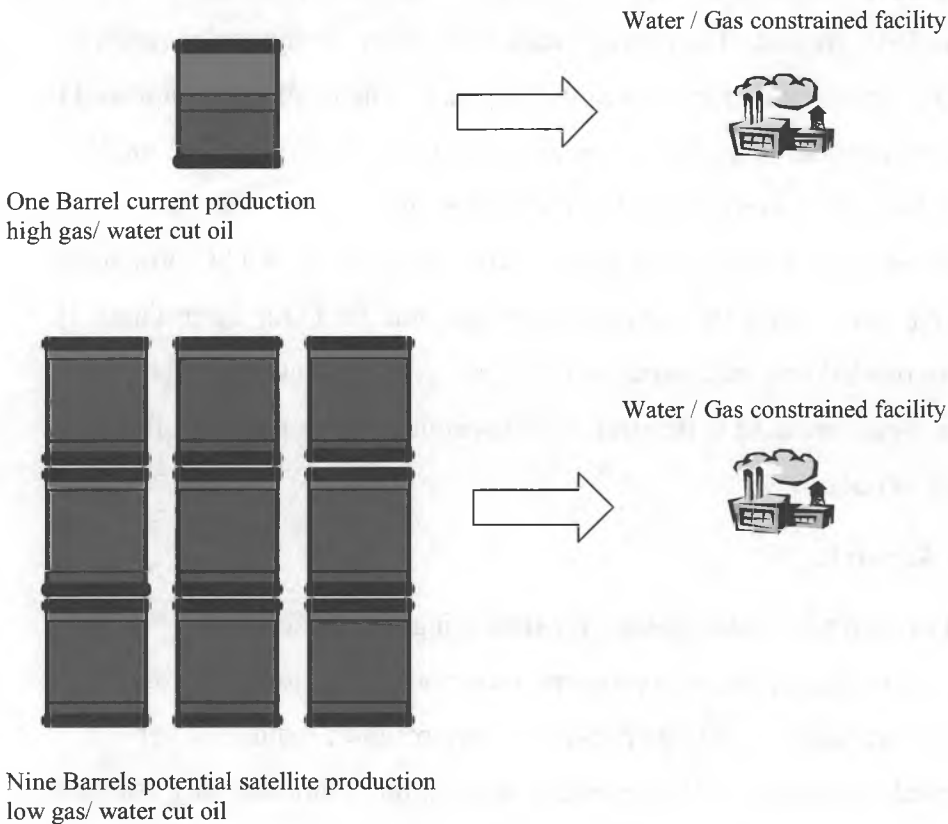
Figure 18 **Hypothetical Backout Illustration**



Backout can be caused by limitations in any or all of the following areas: oil handling, oil transmission, gas handling, gas treating, gas re-injection, water handling, water treating, water injection, electrical generation and pipeline proration. Figure 19 portrays the basic concept of backout, whereby a high GOR and WOR barrel of oil is backed out of the production stream to allow for multiple barrels of low GOR and WOR satellite oil

to be produced. The backed out barrel does have value, if produced, but it is relatively small in relation to the satellite barrels.

Figure 19 Backout concept



Application of General Backout Concepts:

- The backout calculations will be performed monthly.
- The basis of the calculations will be the average monthly allocated production and injection for that month (at the well level) as filed by the operator with the AOGCC.
- To the extent possible, the backout calculations will make use of logic that follows the optimization logic used in actual field operations.
- Adjustments will be made to account for any joint capital project participation by all parties.
- Changes in methodology will be made as appropriate to ensure the results reasonably reflect production adjustments.
- The operator shall be responsible for preparing the backout calculations.

Gas and Produced Water Backout:

This calculation is the first-order factor in calculating total backout, and it is based on plant gas handling and produced water capacity limits, as well as the relative GOR and WOR of the FO and SO streams. The operator uses a computer simulation program to model the day to day processing operations at the facilities. The results are compared to actual operations and calibration modifications are made to the model until the model results match actual operations to within 5%. Then the program is run with its optimization components to determine the basis for the calculations. All SO production is “turned off” in the calculations and the production potential for FO is determined. If there are more than one SO stream, a series of runs are made with one stream at a time “turned off”. The results are used to determine the backout oil and the water oil ratio (WOR) of the backed out oil.

Water Injection Backout:

The operator will have to have methodology for simulating the impacts of reduced/increased water injection rates on the reservoir and production. This information will determine the relationship of oil rate backed out as a result of reduced water injection. Additional adjustments will be made to account for compressibility effects in the reservoir and to minimize possible double counting of backed out production. The WOR is used to determine the water injection backout for each SO stream.

Electrical Power Backout Calculations:

If electrical power generation capacity becomes a constraint to production, it is likely that high water cut wells being lifted with electric submersible pumps would be shut in to free up electrical capacity. It is also likely that these wells would be FO wells. To account for this possibility, a backout amount will be calculated.

The operator will verify each month whether any electrical power related production deferrals events occurred. If not, this calculation is not necessary. If an event occurred, causing lower FO production, the electrical power-related backout volume and the amount of power necessary to avoid this backout will be estimated. The total amount of electrical power used directly by the SO will be tabulated and adjusted for any funded electrical joint capital projects. The backout volume would be allocated according to the

SO usage. If the power necessary to avoid the backout is greater than the total SO usage, then the impact of this calculation is to lower the total calculated backout.

Proration Adjustment Backout Calculations:

Production impacts caused by common carrier or marine capacity prorations are to be shared by the FO and the SOs in percentages proportional to their gross share of pipeline volume. If no proration events occurred for the month, then no calculation will be made.

If there are proration impacts, a table of the **actual** production and the **estimated** production losses (actual proration) will be constructed for each stream. The difference between the target proration and the actual proration is the theoretical adjustment. If the number is negative, the stream will receive barrels and if positive, the stream will deliver barrels. For example, if the FO production rate is 100,000 bopd, and the SO production rate is 20,000 bopd, and a proration event calls for combined rate to be reduced to 60,000 bopd, then the FO rate would be prorated to 50,000 bopd, while the SO rate would be prorated to 10,000 bopd. However, if operational considerations dictate that one or the other stream does not reduce to the prorated value, the difference between that stream's actual production, and the prorated value triggers a backout calculation.

Modification Factor:

The parties will negotiate a further backout modification factor. Each stream's net backout shall be multiplied by the modification factor.

Backout Methodology Alternatives

Several facilities may not have a detailed dynamic plant model to simulate their facility operation. In that case, each facility will have to decide to either develop such a detailed model or devise an alternative method using their existing models to calculate backout. Each of these alternatives has associated costs that would be borne by all parties. Some suggested possibilities are:

- Gather information of shut-in and curtailed wells based on GOR and WOR and determine a theoretical production if these wells were not

curtailed. Prorate this number or an adjusted amount to the third parties for barrel delivery after royalty and tax.

- Hire an independent processor to simulate the field once a year and agree on a representative percentage to be applied throughout the year.
- Use a graph of the KRU or PBU satellite situation based on API, WOR and GOR to estimate the backout percentage.
- As long as the pipelines are not at capacity, the State of Alaska could consider implementing a program that takes the backout barrels from royalty barrels or a portion thereof.

Commercial Considerations

Commercial Framework

The concept and practice of facility sharing is not new to the North Slope of Alaska. Development of satellite fields within and adjacent to existing unit production has required unit operators and owners to create agreements allowing for processing of satellite production through existing or expanded facilities. Kuparuk River, Prudhoe Bay, Lisburne, and Endicott production facilities provide for access to satellite production through facility sharing and services agreements. The other North Slope units have not developed such agreements.

The existing facility sharing agreements were not created with non-unit production in mind, but they are de-facto templates for recent negotiations. The joinder agreement (Appendix D) between Winstar and the Kuparuk River Unit is an example of the use of Ballots 255, 255A, and 260 for the Kuparuk River Unit for third-party production.

Existing North Slope Facility Sharing agreements

The North Slope has a number of existing agreements in place for access to processing facilities. The fields that have not entered into infrastructure access agreements are: Alpine, Badami, Milne Point, and Northstar. There are agreements for Kuparuk (Ballots

255, 255A and 260), Endicott, and Prudhoe Bay/Pt Mac/Lisburne. These are summarized below:

Kuparuk

A series of ballots establishing facility access to the Kuparuk Participating Area (KPA) are 255, 255A and 260. These agreements provide for the processing of a third party's satellite fluids (oil, water and gas), as well as access to injection water, electricity and some common drillsite operations. The ballots offer 'modified available capacity access' and do not provide for 'firm capacity access' to the process facilities. This modified available capacity is based on the principle that the best wells will be produced to maximize facilities oil throughput, regardless of ownership. Therefore, assuming the facilities are operating at full utilization, available capacity for any party is a function of their well stream quality. Third parties pay for this facility access based on their satellite's actual utilization of the facilities.

Ballot 255 is the overriding ballot addressing the main principles of the sharing agreement, Ballot 255A is a detailed description of the methodology for the backout calculation, and Ballot 260 provides access to ancillary services. Ballots 255 and 255A are included in the appendix (E and F).

Ballot 255 Summary:

- Satellites pay a capital access fee to compensate KPA owners for investments made to put the process and related facilities in place. This fee is paid on a per-barrel- of-oil basis.
- The Satellites also pay a fee (on a per barrel-of-oil basis) to cover future process facility abandonment costs.
- Satellites pay fees to cover the satellite's proportional share of fluid processing and other common operation costs. These costs are determined yearly and based on actual costs and production from the previous year.

- Satellites compensate the KPA owners for deferred production in the event KPA production is 'backed-out' or restricted by satellite production. Backout is calculated according to the methodology described in Ballot 255A.
- An oil quality adjustment is made to account for the differences in the characteristics of KPA and satellite oil. The quality adjustment is determined monthly and paid in barrels at Pump Station 1. If satellite crude is superior to KPA crude, the satellite receives net barrels from the KPA. If satellite crude is inferior to KPA crude, then the KPA receives net barrels from the satellite.
- Satellite owners must provide sufficient and timely information regarding the Satellite plan of development and operation to enable the unit operator and KPA owners to assess the demands and impacts the satellite may have on KPA equipment, production and future operations.
- Satellite owners may install and operate their own wells and equipment. Satellite owners are responsible for any and all efforts and direct costs associated with satellite construction, permitting, maintenance, operation, taxes, royalty and abandonment.
- The unit operator is responsible for operating all KPA process facilities, pipelines and all wells on KPA drillsites as well as controlling the rate of production into the facilities. Either the unit operator or a sub-operator will be responsible for operating satellite equipment.
- Fluids must be compatible with KPA equipment. Satellite owners are responsible for any costs to bring satellite fluids into compatibility.
- In the event of competing demands for process capacity, the unit operator will strive to maximize total oil production through unit facilities. The best wells will be produced, the worst wells will be shut-in or curtailed, regardless of ownership. In the event that KPA production is deferred by this optimization of total oil production, KPA owners will be kept whole and compensated through the backout provisions.

- Satellite owners may propose KPA capacity expansions to meet their production requirements. The KPA and various satellite owners will pay for such capacity expansions in accordance to their relative benefit.

Ballot 260

Ballot 260 provides access to a wide range of services on an ad-hoc, as available, basis. Some of the key services included in the document are:

- Mobile and non-mobile equipment
- Emergency fire response
- Spill response
- Waste management
- Camp services
- Materials
- Solid oily waste management

Endicott:

Endicott has two facility sharing agreements (FSA) in place for Eider and Sag Delta North satellites and is a receiving entity under the IPA (Initial Participating Area) Ballot Agreement 98-202: Authorizing Use of IPA Equipment and IPA Services. These agreements provide for the development of the satellites using the Endicott facilities to process fluids. The general terms of the FSAs are outlined below and a summary of the IPA Ballot Agreement 98-202 is provided in the Prudhoe Bay Unit (PBU) and Pt. Mac/Lisburne section.

Endicott FSAs Summary:

- Describes scope of satellite operations and equipment needs
- Provides access to Endicott facilities for operations, gathering and treating of production

- Determines the satellite responsible for paying for any facility modifications
- Establishes fees for various services provided
- Establishes equipment access, O&M, abandonment, excess power, and make-up water fees
- Establishes fees for additional processing operations as applicable
- Sets production capacity priority based on competitive WOR/GOR if capacity limited
- Provides backout calculation for production and value adjustment for crude quality differences
- Provides fuel in-kind calculation

PBU and Pt. Mac/Lisburne:

There are three primary categories of facility sharing agreements relating to PBU facilities and services. First, there are a number of agreements that relate to operations of the Lisburne Production Center. Second, there are agreements related to processing PBU satellite production in facilities originally developed to produce the main Prudhoe reservoir (“IPA Facilities”) (Ballot 97-196). Third, there is an agreement authorizing third-party sharing of certain equipment and services (“IPA Equipment and Services”) (Ballot 98-202). The PBU Owners also have entered into agreements that address the use of specific equipment.

A summary of these categories of agreements follows:

1. Lisburne Production Center Agreements

The Lisburne Production Center (LPC) was developed to process production from the Lisburne Reservoir. In the early 1990s, agreements were developed to address what is called the Greater Pt. McIntyre Area (“GPMA”). These agreements allow the Pt. McIntyre, Niakuk, West Beach and North Prudhoe reservoirs (“Sharing PAs”) to be processed through the LPC with Lisburne production, and for sharing between the IPA

Owners and the owners of the participating areas within the GPMA of certain support facilities, electrical power, vertical support members, source water and other facilities and services.

2. Facility Sharing Authorization Agreement (Ballot 97-196)

This agreement provides for the development of a Facility Sharing Agreement (FSA) for each satellite field under which production fluids from that satellite could be processed through the use of IPA Production Equipment. There are currently no FSAs with parties external to the Prudhoe Bay Unit.

Owners of a satellite seeking access to IPA facilities must provide specific information regarding the plans for development and operation of the satellite to enable the IPA owners to evaluate demands and impacts that regular production from the satellite will have on IPA production equipment and services, field development plans, and production levels. This information includes:

- (i) The scope and timing of Satellite development, including location of Satellite well pads and facilities, projected number and timing of Satellite wells to be drilled on each well pad, and identification of specific facilities for which access, modification, use or tie-in is proposed;
- (ii) Projections of satellite production to be delivered to IPA production equipment, the quantities of “returned” gas (gas lift, fuel or injection) and satellite produced water to be made available by the IPA owners to the satellite, all on a year-to-year basis;
- (iii) Description of electrical power, gas, make-up water or other IPA production equipment and services for use by the satellite; and
- (iv) Description of the stratigraphic horizon and areal extent for the portion of the satellite reservoir proposed for development with compositional descriptions and producing characteristics (e.g. temperatures and pressures) of the anticipated satellite production.

Based on this information, the IPA owners may enter into an FSA that will specify appropriate terms and conditions including:

Facility Sharing Analogs

The concept of Facility Sharing is a growing consideration in mature oil and gas basins around the world. Aside from the examples mentioned above on the North Slope, publicly available information pertaining to facility sharing agreements in other countries exists. Understanding these agreements is useful when negotiating future agreements for the North Slope. In general, the guiding principles from both the United Kingdom (U.K.) Code of Practice and Alberta's Jumping Pound formula are aligned with the existing North Slope facility sharing agreements. Both Alberta and the Offshore U.K. have mature oil and gas basins where the facility sharing concept has proven beneficial for operators, third party producers, and the government. Both examples reviewed provide for regulatory interdiction as needed to resolve disputes between negotiating parties, although the UK Code of Practice has not had to rely on the government intervention process to date. Emphasis on a cooperative approach to facility sharing has been successful in negating the need for government interdiction. Both facility sharing approaches outlined below are proven starting points for successful negotiations. Existing agreements between unit partners on the North Slope present the obvious starting point for new facility sharing agreements, and the highly cooperative approach adopted in the United Kingdom sets a good example for expanding these existing agreements to meet the needs of an expanding group of potential producers.

UK Offshore Infrastructure Code of Practice

The United Kingdom's "Indicative Tariff" Code of Practice for offshore oil and gas infrastructure is a cooperative industry document on the rules and procedures governing third party access to these facilities. This document provides a framework for easy, fair and non-discriminatory access to offshore oil and gas facilities. The process is supported by the oil and gas industry. It is not mandated or enforced by a government agency, however if a dispute over access does arise, there is a government body that has the legal authority to settle the differences. The framework for third party facility access is a combination of the Offshore Infrastructure Code of Practice for conducting commercial negotiations and the legal backstop of appealing to the UK Secretary of State for Trade and Industry to settle disputes over access. The real strengths of the system are the

Owners and the owners of the participating areas within the GPMA of certain support facilities, electrical power, vertical support members, source water and other facilities and services.

2. Facility Sharing Authorization Agreement (Ballot 97-196)

This agreement provides for the development of a Facility Sharing Agreement (FSA) for each satellite field under which production fluids from that satellite could be processed through the use of IPA Production Equipment. There are currently no FSAs with parties external to the Prudhoe Bay Unit.

Owners of a satellite seeking access to IPA facilities must provide specific information regarding the plans for development and operation of the satellite to enable the IPA owners to evaluate demands and impacts that regular production from the satellite will have on IPA production equipment and services, field development plans, and production levels. This information includes:

- (i) The scope and timing of Satellite development, including location of Satellite well pads and facilities, projected number and timing of Satellite wells to be drilled on each well pad, and identification of specific facilities for which access, modification, use or tie-in is proposed;
- (ii) Projections of satellite production to be delivered to IPA production equipment, the quantities of "returned" gas (gas lift, fuel or injection) and satellite produced water to be made available by the IPA owners to the satellite, all on a year-to-year basis;
- (iii) Description of electrical power, gas, make-up water or other IPA production equipment and services for use by the satellite; and
- (iv) Description of the stratigraphic horizon and areal extent for the portion of the satellite reservoir proposed for development with compositional descriptions and producing characteristics (e.g. temperatures and pressures) of the anticipated satellite production.

Based on this information, the IPA owners may enter into an FSA that will specify appropriate terms and conditions including:

i) The specific O&M fee, capital access fee, abandonment fee, backout, and volume adjustment factor (VAF) as well as fees for use of IPA area equipment and IPA services in support of subsurface satellite operations, additional processing operations and satellite drilling and construction activities, and fees for make-up water, additional electrical power or other items.

a) The O&M fee is to reimburse the IPA owners for the satellite's proportionate share of the IPA production equipment and services producing costs for base processing operations.

b) The capital access fee is to reimburse the IPA owners for investment in IPA production equipment.

c) The abandonment fee is to reimburse the IPA owners for a satellite's proportionate share of the estimated future abandonment costs for IPA production equipment accessed by that satellite.

d) Backout is the estimated volume of IPA oil that cannot be produced during a specified time period because of the processing of satellite produced fluids through IPA Production Equipment. The Satellite is responsible for keeping the IPA whole on deferred production by reimbursing the IPA for backout with a volume of satellite production.

e) VAF is a volume adjustment to a satellite's oil volume that reflects, among other things, the differences in physical quality, compositional differences and handling considerations of produced fluids from the IPA and satellites.

(ii) Incorporation of specific terms and conditions which address any issues raised by the information provided above including the commercial terms required for any satellite modification, joint equipment or additional services requested.

(iii) Scope and timing of development (including all satellite modification and joint equipment requirements), range of rates for satellite production and reservoir boundaries for which use of IPA production equipment and services will be allowed.

3. Ballot Agreement Authorizing Use of IPA Equipment and IPA Services (Ballot 98-202)

This agreement authorizes the use of certain IPA area equipment and services (not including oil and gas processing equipment) by other units/participating areas (receiving entities), establishes terms of compensation for use of IPA area equipment and services, and defines the allocation of liability between IPA owners and the receiving entities with respect to the use of IPA equipment and services.

IPA equipment and services under Ballot 98-202 are intended to be for incidental use of receiving entities. Use of IPA area equipment and services for other than incidental use would be subject to a separate agreement negotiated on a case-by-case basis. (Incidental use means use of equipment and services by a receiving entity that is in excess of the IPA owners' needs at the time of such use and that is insubstantial when compared to the IPA owners' use of such equipment or services.)

Equipment and Services include:

A) Mobile & non-mobile equipment	K) Projects & construction
B) Airport shuttle bus services	L) Overhaul & rotating equipment
C) Sewage disposal	M) Scheurle trailer
D) Production lab	N) Investment recovery
E) Wellhead services	O) Flow measurement
F) Hot water plant	P) Miscellaneous services
G) West Dock staging area	Q) Mukluk Pad
H) Drum disposal	R) CTD work platform
I) Halon support services	S) Security checkpoint
J) Camp services	

4. Specific Equipment: Grind and Inject Plant Operating Agreement (IPA Ballot 97-201)

This agreement allows authorized parties to use the Grind and Inject Plant to dispose of drilling waste for a fee.

Facility Sharing Analogs

The concept of Facility Sharing is a growing consideration in mature oil and gas basins around the world. Aside from the examples mentioned above on the North Slope, publicly available information pertaining to facility sharing agreements in other countries exists. Understanding these agreements is useful when negotiating future agreements for the North Slope. In general, the guiding principles from both the United Kingdom (U.K.) Code of Practice and Alberta's Jumping Pound formula are aligned with the existing North Slope facility sharing agreements. Both Alberta and the Offshore U.K. have mature oil and gas basins where the facility sharing concept has proven beneficial for operators, third party producers, and the government. Both examples reviewed provide for regulatory interdiction as needed to resolve disputes between negotiating parties, although the UK Code of Practice has not had to rely on the government intervention process to date. Emphasis on a cooperative approach to facility sharing has been successful in negating the need for government interdiction. Both facility sharing approaches outlined below are proven starting points for successful negotiations. Existing agreements between unit partners on the North Slope present the obvious starting point for new facility sharing agreements, and the highly cooperative approach adopted in the United Kingdom sets a good example for expanding these existing agreements to meet the needs of an expanding group of potential producers.

UK Offshore Infrastructure Code of Practice

The United Kingdom's "Indicative Tariff" Code of Practice for offshore oil and gas infrastructure is a cooperative industry document on the rules and procedures governing third party access to these facilities. This document provides a framework for easy, fair and non-discriminatory access to offshore oil and gas facilities. The process is supported by the oil and gas industry. It is not mandated or enforced by a government agency, however if a dispute over access does arise, there is a government body that has the legal authority to settle the differences. The framework for third party facility access is a combination of the Offshore Infrastructure Code of Practice for conducting commercial negotiations and the legal backstop of appealing to the UK Secretary of State for Trade and Industry to settle disputes over access. The real strengths of the system are the

adherence to a timeline for the negotiation and the support from all parties to have a practical means of an early understanding of the availability and the approximate costs of bringing and processing hydrocarbons in existing facilities.

The owners maintain an up-to-date database on their offshore infrastructure. When a potential user requests this data, the owner has 10 days to respond with the requested data as well as an indication of the probable tariff. If interested in proceeding, the user formally contacts the owner and provides specifics as to the kind of hydrocarbon composition and specifications, along with the development strategy. Within 30 days, or a mutually agreed-upon timetable, the owner must reply to the prospective user with a detailed technical response to the specifics of the requested facility use. If the request from the user fits with the available access from the owners, the negotiations continue with another 30 day clock. The parties may agree in the process of these final negotiations to substantially change the standard terms they started with. The UK Department of Trade and Industry (DTI) website is a valuable source of information, and the Code of Practice can be found on their website: <http://www.og.dti.gov.uk/regulation>

The self-maintained database of the infrastructure owners is expected to include the following data:

- a. Technical description: Hydrocarbon entry specification, pressure regimes/compressor curves at entry and exit, dehydration regime, process diagrams and other operating conditions;
- b. Operational capability including measures of past performance and reliability. Planned changes affecting operational capability should be indicated;
- c. Services that can be provided;
- d. Indicative price of services;
- e. Indicative forecast of available capacity normally for 5 years ahead, but for a longer period for significant infrastructure; and
- f. Pertinent general contract terms: lifting procedures, ownership, priorities, system allocation principles, substitution terms, voting rights, etc.

Although this information does not constitute an offer capable of acceptance, it provides to the user the indicative terms, which can be used as a yardstick as negotiations progress toward settlement.

The prospective third-party user is expected to provide the following specific information on the service requested:

- a. Production profiles;
- b. Compositions;
- c. Start-up date;
- d. Broad outline of development concept;
- e. Hydrocarbon specification (such as H₂S, CO₂, gravity etc).

While this 1996 offshore infrastructure code of practice is a working process for facility owners and potential third party users, it is still an evolving procedure. In 1998, the Petroleum Act was instigated to provide an appeal process for the Secretary of State to settle disputes over access. Further to this, in the spring of 2001, the UK Department of Trade and Industry responded to allegations that access to infrastructure was still a commercial barrier to oil and gas development with a study on the effectiveness of the voluntary Infrastructure Code. The results of the study found that although it is not necessary to replace or update the existing code, it is imperative to continue to check on its effectiveness at least every three years. At this time, even though the code is not a perfect system, it is still supported by the industry. Clearly this voluntary arrangement, in combination with a legal backstop for the governing body to step in to provide a means to settle disputes over access, is recognized as crucial for their continued offshore oil and gas development. Currently, Work Groups formed by the DTI are preparing a proposal to amend the Infrastructure Code of Practice with the key changes being:

- Allowing for the Secretary of State to become automatically involved in an infrastructure access request if insufficient progress is being made after a certain period (to be determined) and allowing the Secretary to set a tariff.
- Allowing for the provision of more information and transparency.

It is expected that this proposal will be published in May 2004.

There are no published examples of how the Code of Practice has worked, as these negotiations for infrastructure terms are confidential. Per the Code, indicative tariff offers are reported to the DTI, which are then published.

The Secretary of State, to date, has not been asked to formally intervene to set tariffs or enforce access. Operators have preferred to work out agreements among themselves rather than taking the risk of government intervention using methodology that is not clearly defined. The Secretary's office has participated informally in cases to move negotiations along when companies complain.

Alberta's Facility Sharing Agreement, the Jumping Pound Formula

Alberta Canada also has an industry-agreed-upon voluntary guideline for calculating oil and gas processing tariff ranges. The access to infrastructure is agreed to be an open and non-discriminatory access, in facilities where capacity is available. The Jumping Pound methodology is based on an industry-derived formula. The formula was developed for a case decided by Canada's National Energy Board (NEB) for the processing tariff charged at a gas processing plant at Jumping Pound in 1990.

The Alberta Jumping Pound Formula (JP 90/ 95) was developed jointly by a number of industry organizations as a guideline for parties to use in negotiating fair and reasonable fees on an everyday basis and to assist in dispute resolution. The Alberta Energy and Utilities Board (EUB) supported the initiative but did not play a major role in the development of the actual formula. The formula was developed to determine the components which form any tariff rate for oil and gas processing at plants, e.g. rate of return, rate base and range, operating costs, plant capacity, and special fee considerations. The two documents describing the JP 90/95 formula are *Gas Processing Fee, Jumping Pound 1990 (Jp-90)*, January 1990, and *Joint Industry Task Force Report On Processing Fees JP-95*, April 15, 1996, which have some general examples of cases.

The calculation for the fee establishing the calculated return on the capital investment for the Jumping Pound Formula uses the original cost of the facilities as the Capital Base, depreciated in a straight line over the life of the project (normally set at 20 years). A return on capital is established as 15% before tax rate of return on the capital, and is

allocated among the owners of the facility as a capital allowance. Based on these costs, the fee for the facility access is prorated per total throughput. Additionally, there is a component of the formula that accounts for the sharing of the operating costs of the facility. This component is generally also prorated on a production basis.

Although the formula is used voluntarily by the industry as a starting place for negotiations on facility access, the key to Alberta's facility sharing practice is the regulatory board's legal power to ensure a third party gains access to infrastructure.

Where disputes on processing fees cannot be resolved on a voluntary basis, there is provision in the Alberta Oil and Gas Conservation Act (OGCA) for a party to apply to the EUB to set the fees. When the EUB has received an application and determines that it is complete, a public hearing is scheduled to consider the application. The EUB has stated that, if application is made to the EUB to set processing fees, it will use the Jumping Pound Formula, unless there were compelling opposing reasons. The EUB gets very few applications requesting the setting of processing or transportation fees (one or two a year, typically), and has not yet set any such fees. All applications requesting fee-setting were withdrawn while the applications were being processed. The EUB encourages parties to continue negotiations or mediations in parallel with filing an application with the EUB. Typically once a EUB hearing date is set these negotiations or mediations result in resolution as the opposing party often does not want to be drawn into the regulatory arena through the public hearing process. Although the EUB has not yet set any fees, it remains prepared to do so.

The Alberta law dealing with third party access is set out in Part 9 of the OGCA. Disputes on access may result from a number of issues - volumes, delivery points, fees, drainage issues. The application requirements are set out in EUB Guide 65. (The OGCA and Guide 65 are available on the EUB web site www.eub.gov.ab.ca.) If the EUB approves an application, access is granted by means of an order which declares a party to be a common carrier (access to a pipeline), common processor (access to a gas processing plant), or common purchaser (access to market). An order can simply be a declaration; for example, Company XYZ is a common processor of gas from the Pipestone Viking F Pool. Additional direction can also be included to give effect to the order; for example, the order can allocate production among producers in a pool (a usual provision), specify the delivery point, or set out the fees. Usually an order does not deal

with all of these issues; the nature of the dispute that resulted in the application being filed with the EUB determines which issues are addressed. When a party is declared to be a common carrier, processor, or purchaser the OGCA requires it to treat parties without discrimination within the limitations of the order (within a pool, typically).

The EUB has no data to know how widely JP90/95 is used as a benchmark, as the vast majority of companies who want capacity in facilities they do not own (whether processing plants or pipelines) are able to privately negotiate satisfactory voluntary arrangements, and the matter does not come before the EUB. There is no requirement to file contracts that result from these negotiations.

Independent Oil Companies' Perspectives

PRA surveyed 15 independent oil companies currently interested in Alaska oil and gas exploration to get their perspective on facility access and to identify their needs in creating a template for negotiating access. Five of the companies contacted responded to the survey, and others provided feedback through informal discussions, including open discussions during a meeting of independent oil companies hosted by Alaska Governor Frank Murkowski in Juneau in December of 2003.

The questions asked of these companies are listed in Appendix A.

The key areas identified as concerns and issues are:

- Backout calculations;
- Capital access fee methodology;
- Timing of negotiations;
- Insurance requirements;
- Operatorship;
- Trust and access to supporting information.

Summary of Independent Company Concerns:

Backout calculations

manner. The operators recognize that a business opportunity exists for establishing a formal agreement with fair terms for processing third party production volumes in existing infrastructure.

In the State's view, expressed in the CHARTER FOR DEVELOPMENT of the Alaskan North Slope, the Commissioner of Natural Resources possesses the statutory, regulatory and contractual authority to require working interest owners to provide other producers access to production and other facilities, on terms that are non-discriminatory, just and reasonable. Under the Charter for Development, the Commissioner may require access whenever necessary to

1. maximize the economic and physical recovery of the State's oil or gas resources,
2. maximize competition among parties seeking to explore and develop the resources,
3. minimize the adverse effects of exploration, development, production and transportation activity,
4. or otherwise to protect the best interests of the State.

Also, as stated in the CHARTER FOR DEVELOPMENT of the Alaskan North Slope, BP and ConocoPhillips take no position on the State's view. BP and ConocoPhillips commit that they will not unreasonably withhold their voting support as facilities owners for allowing nearby satellites to have access to existing unit facilities on reasonable commercial terms.

Recent history indicates that the owners and operators are willing to negotiate access.

PRA compliments the commitments stated above and makes the following recommendations:

1. Nearly all of the existing facilities have the potential for developing or a precedent for facility sharing agreements. The Independent producers should expect to be able to negotiate an acceptable agreement. The negotiations should be initiated by independent producers as early as possible.

2. The largest obstacle to successful negotiations is a lack of trust. Development and communication of a process for third-party facility access which is fair and transparent will help to resolve this lack of trust, and create opportunity for expanded resource development.
3. The Independents need to provide operators with a well thought out development plan with as many crude characteristics as possible.
4. The most critical technical issue is the calculation of the backout volumes. The operators need to communicate the backout methodology and be able to respond to requests in a timely manner.
5. The Independents need to recognize backout is a valid concept, representing real lost or deferred barrels to the facility owners.
6. Both parties need to be ready to compromise on the backout methodology to simplify the calculations for fields without a detailed dynamic plant model.
7. The State of Alaska has shown interest in investigating methods to defray the backout impacts to the Independent producers, and this should be continued.
8. Significant positive progress has been made through the compilation of this report, and further investigation and communication should be energetically pursued to assure continuation of this progress.

Information Request for CPAI Operated Fields

- What are the maximum capacities, current and forecast throughput of oil, water and gas, and constraints on production facilities, from transportation pipeline to drill site level?
 - Are there any “quick wins” to increase available capacity?
- What are the opportunities and constraints associated with input oil quality?
 - What are the input specification requirements for the processing plants?
 - How leveraging is oil quality on processing and transportation costs?
- What agreements are currently in place which would impact facilities access?
 - Could you provide a summary description and/or copies of these agreements?
- If you were to design a template to offer facilities access, what would be the key components?
- How would you rank potential access opportunities for the ConocoPhillips operated fields?

Appendix C

Operator Facility Sharing Contacts

ConocoPhillips Alaska Inc.

Jim Ruud: 907-263-4933 Manager Land- Alaska

John Cookson: 907-265-6547. Engineering Advisor - Greater Kuparuk Area

Dan Kruse 907-265-1315 Manager - Subsurface GPA

John Whitehead: 907-265-6513 Vice President Western North Slope

Darren Jones: 907-263-4431 Vice President Greater Kuparuk Area

Meg Yeage: 907 263-3710 Vice President Greater Prudhoe Bay Area

<http://www.conocophillipsalaska.com/facilityaccess/>

BP Exploration (Alaska) Inc.

Mike Koy:	(907)561-5111	Commercial Manager, GPB Asset

R.L. Skillern:	(907)561-5111	Land Negotiator, Alaska

Daryl Kleppin	(907)561-5111	Commercial Manager, ACT! Asset

Appendix D

Joinder Agreement

Appendix E

KRU Ballot 255

Appendix F

KRU Ballot 255A

Contents #15-23
Continue in
SB 192 (File 2)