
Issue and Recommendation Discussion Papers

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Allowable Costs Definition Alignment

Situation

It is desirable to establish a clear set of operational rules regarding Allowable Costs to address which costs are eligible, and particularly to clarify boundaries between non-eligible production, eligible gathering, compressing and processing, and non-eligible marketing costs. Clarity in distinguishing operating costs from capital costs is also desirable, as is common understanding of processes available to resolve differences and disputes.

The areas for review are described below.

Direct Costs

- Industry has developed a body of understanding on the definition of direct costs versus indirect costs for joint venture billing purposes. Over the years the Petroleum Accountants Society has developed and updated model accounting procedures which constitute generally-accepted industry practice to the date of the model. The models lay out definitions and options to facilitate the negotiation of actual joint venture agreements, and suggest which costs may be charged as direct costs, either requiring or not requiring approval by the owners. It is industry's opinion that working interest owners and royalty interest owners share a common stakeholder interest in the property, in the aspects of the joint operation which are directly related to the gathering, compression and processing of gas. Thus any cost which is clearly within the realm of Allowable Costs should be defined consistently by the working interest owners and royalty owners.
- In the case of non-joint venture properties, although there is no joint venture agreement in place and no owner votes on costs requiring prior approval, the Petroleum Accountants Society model agreement, which contains an extensive interpretive section, can provide a policy structure for equitable treatment of royalty owners. In reviewing costs claimed as Allowable Costs for non-joint venture facilities, the model accounting procedure can act as the test of normal practice by prudent operators and partners.

A hierarchy of guidance and decision making might be:

- Mines and Minerals Act/Freehold Mineral Rights Tax Act
- Natural Gas Royalty/Freehold Mineral Rights Regulations
- Gas Royalty/Freehold Mineral Tax Policies and Procedures
- Specific Joint Venture Agreement
- Petroleum Accountants Society of Canada model accounting procedure and interpretive guidelines

Indirect Costs

Costs which are not specifically identified as direct costs are indirect costs. Joint venture agreements provide for an overhead charge, usually 10%, which is consistent with the gas royalty guidelines 10% allowance for indirect costs.

Recommendations

- Publish expanded and updated Allowable Cost Guidelines (Policies and Procedures) which clearly state the Crown's position relative to eligible and ineligible costs and which state that in those instances where clarity of intent is not obvious, that decisions will be made based on published industry practices as agreed by the Crown or Generally Accepted Accounting Principles.
- These rules apply to facilities directly involved in the gathering, compressing and processing of the Crown's share of natural gas. Costs associated with either production or marketing are not eligible for consideration in determination of Crown charges and must be identified and eliminated.
- The guidelines must address the boundaries between eligible and ineligible processes (production/gathering, compressing, processing/marketing) and the hierarchy of authorities to be reviewed to resolve audits or disagreements on interpretation.
- Insurance premiums should be specifically disallowed, and the full cost of reconstruction subject to insurance recoveries specifically allowed, as recommended elsewhere in this report.
- The guidelines should state that environmental costs that are currently identified as 'support' be considered overhead, costs that are identified as monitoring be recognized and accepted as being direct costs and costs incurred in ongoing operational activities on-site or in the immediately impacted area be recognized as direct (Allowable) costs. For example costs associated with air quality or ground seepage monitoring which are incurred because of government or industry initiatives or are in place because they comply with publicly identified corporate policy (to the extent the costs qualify under PASC) will be recognized as direct (Allowable) costs.
- Common costs such as roads, airstrips or housing should be allocated according to use, first between petroleum and gas and then by a predetermined percentage of gathering related costs as being production related (ineligible) costs. ADOE should review and determine the appropriate range. A range of 15-20% of gathering operating and capital costs is suggested. There may be risks associated with tying such a cost 'reduction' to one measurement. These risks will be identified and remedial action taken during the review.
- A review of the Crown's position should be undertaken relative to the current treatment of, capital and operating costs for cycling schemes.

As these recommendations are independent of the other task force recommendations and as there are no computer system investments or associated lead times it is recommended that these items be addressed and finalized by August, 1998.

Process

The following process is recommended:

- Allowable Cost Guidelines (Policies and Procedures manual) will be updated twice per year with interim updates provided each month via the Department's Information Bulletin process. One or more of the following occurrences will trigger such updates:

- The Petroleum Accountants Society publishes a bulletin establishing or clarifying industry operating policy,
 - The results of an appeal or audit offer clarification,
 - Any aspect of an existing policy is clarified by another means, or
 - The Minister revises, including introducing or deleting, legislation driving changes or clarification.
- In order to eliminate costs incurred in relation to the production and marketing functions, the following steps might be taken:
 - Certain cost categories are identified as non-eligible and are eliminated (e.g., produced water handling, well work over).
 - Certain categories of costs should be subject to agreed percentage allocations to non-eligible functions. (e.g., gathering system labour). NOTE: While ideally this would be facility by facility, the consensus of the task force is that the ADOE will review recent audit files and establish a factor relative to gathering system direct costs which may be used as a proxy for the costs for Allowable Cost purposes. The results of this investigation may be relevant in other areas of 'split' costs such as roads and related infrastructure such as housing.

Benefits

- Operators account to one set of Allowable Cost books. The same Allowable Costs, with the noted exceptions, apply for joint venture owners, Crown (and other) royalty owners and custom processors. Multiple cost accounting procedures are eliminated.
- Redundancy in other cost submissions (e.g., freehold royalty or custom processing fee calculations) may be reduced.
- Audit costs are reduced for Crown and industry, as both industry and Crown auditors are following the same guidelines. These Policies and Procedures are sufficiently clear to avoid most differences of interpretation. In cases of differing opinion, reliance of both parties on the same interpretive text should enhance the resolution process.
- Joint audit efforts by working interest owners and royalty owners, including the Crown for Allowable Costs is enabled, which may further reduce audit costs for both industry and the Crown.
- Appeals of audit findings may be significantly reduced.
- Better education of industry accounting staff should reduce frequency of errors in interpretation of Allowable versus non-Allowable Costs.
- Reduced amendments of Allowable Cost submissions (AC4) should result from better understanding of the guidelines.
- Early and regular updates of Policies and Procedures clarifying the outcomes of appeals and rulings will enable Industry to incorporate the refined rules into current and future period Allowable Cost accounting.

- Clear and concise Policies and Procedures may add discipline to the royalty related accounting for 100% owned facilities.
- Clarity of Crown Policies and Procedures may add credibility to use of Crown Allowable Cost submissions as reasonable gathering, compression and processing costs for other royalty owners.

Drawbacks/Concerns

- The exercise of explicitly identifying each type or grouping of direct and ineligible costs will necessarily be undertaken by ADOE and will require a substantial level of investigation, particularly with regard to the boundaries between eligible and non-eligible functions. This may entail debate and lobbying. The detailed lists of eligible/ineligible, capital/operating costs will be continually be incomplete and given the evolution of the natural gas business and engineering advances these will be continuously in need of review and updating and defending. There is no quantifiable cost for this and it is uncertain whether the 'new' costs would or would not exceed the level of existing costs.
- Particularly contentious items such as plant/facility reclamation and pipeline abandonment costs will require detailed evaluation and public debate before the Crown could see them included in the eligible category. It is recommended that this issue be investigated and resolved in a timely manner.

Costs

Costs associated with the recommendation:

- Ongoing cost of maintaining the expanded Policies and Procedures manual and Information Bulletins – not a substantial incremental cost .
- No systems development costs.

Replace the Corporate Effective Royalty Rate with the Facility Effective Royalty Rate

Situation under the Current Regime

The 1994 royalty regime implemented use of corporate pool capital cost allowances, rather than capital cost deductions at a facility level. In order to accomplish this, the concept of Corporate Effective Royalty Rate (CERR) was established. The CERR is a calculation of total corporate average gross royalty rate, taking into account all revenues, total corporate share of capital cost allowances and average Crown interest across all producing entities.

This process was intended to simplify the royalty process. The result, however, has been more complexity and confusion over the actual royalty burden of any particular royalty entity. The impacts were as follows:

- Royalty for a well may be significantly over or under stated, as capital cost allowance deductions taken at the corporate level do not match those which should actually apply to the well.
- Crown royalty invoices show only gross royalties, with deduction of Unit Operating Cost Rates by well. The capital cost allowance is shown simply as a corporate deduction.
- Companies had to develop allocations to distribute the capital cost deduction to properties. This was complicated by distribution created by this process, causing the total to differ from the sum of the parts.
- Corporate analysis of a well's contribution, including purchase and sale analysis, was made much more difficult. Further to this, industry economic evaluation models had to be updated to properly account for the actual economic royalty for wells, as opposed to the invoiced royalty.
- The value of a well could vary dramatically among its working interest owners because of significantly different CERR impacts. Buying or selling properties could have an impact on the CERR which could seriously impact business decisions.
- The CERR, and consequently royalty for all properties of a royalty payer, changes with every amendment of revenue, costs or volumes.

Options

- Status Quo - CERR
- Facility Effective Royalty Rate
- Plant type Effective Royalty Rate:
- Entity Owner Effective Royalty Rate: same issues as today – no gain

Recommendations

- Eliminate the use of Corporate Effective Royalty Rate.
- Apply capital cost allowance deductions from gross royalty at the facility level for each royalty client, using the well royalty effective rate.
- Continue actual allowable capital cost submissions by facility.
- Calculate capital cost rates for each AEUB facility, using all capital costs submitted.
- Apply capital cost rates by a price-adjusted throughput allocation.
- Capital cost rates should be adjusted for all volume and price variance between actual and estimate, as well as amendments and audits, by a 13th month process. The 13th month process should be run twice a year to ensure all current data are taken into account. Later amendments due to audit or otherwise, would be applied to the 13th month calculation for the current year.
- Show net royalty per AEUB facility on Crown royalty invoice.

Benefits

- Allowable cost deductions are properly matched to the wells making use of the facilities, generating realistic net royalties for each well or producing entity.
- Each invoice and the supporting Crown Royalty Detail will identify gross and net Crown royalty at AEUB facility level.
- Economic decisions are based on the attributes of the property in question versus the current system where a royalty payer's entire asset mix characteristics impact the specific entity's royalty load.
- Eliminates issues surrounding impacts of freehold and out of province volumes.
- Eliminates submission of capital cost allocations to owners by operators.
- Eliminates calculation and amendment of CERR by ADOE, and resultant royalty adjustments.
- Enables a return to net royalty holiday benefits (see separate recommendation).
- Simplifies royalty business rules.

Costs

- MRIS will require coding changes.

- Service provider systems will require changes.
- There will be some royalty distribution (often the reverse of distribution caused by the 1994 regime) from the change of effective royalty rates.
- There will be some distribution from use of volume allocations instead of ownership allocation, particularly when an owner has greater ownership than his throughput (not compensated for by excess usage fees to other owners or custom fees).
- There will be some royalty re-distribution from use of the average capital cost per designated plant.

Eliminate the Custom Processing Adjustment Factor

WHY: Difficulties with present system

- Eliminates, for Crown royalty purposes, the facility operator being required to track custom processed volumes.
- Substantial royalty leakage opportunities are felt to exist in this area – high audit/compliance costs.

Option

- In order to eliminate the Custom Processing Adjustment Factor a postage stamp rate for Capital must be established. Based on investigations relative to the CERR the capital postage stamp deduction would be set at each Alberta Energy and Utilities Board Facility. NOTE: A dependency exists - Unless a postage stamp methodology is employed for Allowable Capital the CPAF can not be eliminated

Related Activities and Considerations

- Above noted issue on treatment of Allowable Capital costs.
- Need to consider the implications of royalty payers who custom process in only part of the AEUB facility.
- Need to build the methodology for updating the Allowable Capital postage stamp rates.
- Treatment of excess capacity charges to be addressed.

Recommendation

Introduce a system based on allocating capital costs at the EUB facility level so as to eliminate need for the claw back mechanisms contained in the CPAF. Options are numerous, the objective would be to utilize a mechanism that most closely reflects use patterns at the facility and resulting value of service. Most likely approach involves allocating capital based on value/volume of throughput and establishing operating cost allowances for Custom Processing.

Updating Allowable Cost Rates

Situation with Present Process

Unit Operating Cost Rates (UOCR) are calculated using actual operating costs for each of 38 designated plants. In the case of the five defined plant types, UOCR's are a postage stamp rate established using inflation and volumetric adjustments to a pre-determined base. The base being the average of 1990, 91 and 92 production and costs. Once the UOCR is established is used on a prospective basis only. Under the current business rules, a UOCR is not revised.

Each year a new set of UOCR's is calculated and again used prospectively. Reflected in the then current year UOCR's are the following:

- Estimate-to-actual revisions of operating costs (38 designated plants only).
- Audit adjustments to operating costs (38 designated plants only).
- Estimate-to actual volume adjustments (5 plant types and each of 38 designated plants).
- Inflation factor impacts.

This 'roll-forward' mechanism was implemented in 1994 with the intent of reducing royalty amendments. It was not anticipated that the year to year fluctuations in the UOCR's would be significant. This has not been the case as the UOCR's have in fact swung significantly, on occasion becoming negative. The most significant contributor to the swings has been the volumetric adjustments. The impact of prior-year audit adjustments/industry refilings on a specific plant type UOCR is relatively minor.

Thus, there is no motivation today to revert to adjustment of royalty statements for prior years. That would impose a severe administrative burden on ADOE with little benefit to industry. In situations where properties have been sold since the prior years audited, ADOE can reasonably continue to charge/credit the industry for these prior year adjustments via current year rate changes. This is the current practice, and impact on the industry is limited. Where the time period allowed for purchase/sale adjustments has passed, the new owner is liable, and where the old owner is liable, ADOE can look to the industry to settle reallocation among themselves.

Difficulties with the Present System

- Purchasers of properties experience unanticipated hardship/windfalls when UOCR's are dramatically changed due to prior period adjustments including volume impacts at a designated facility or a plant type.
- The UOCR updating formulae are extremely complex and difficult to emulate. Forecasting is difficult.
- Corporate results may be materially changed by the swings in UOCR rates.

Recommendation

Introduce the concept of a “13th month” so as to more closely match costs with revenues. In the case of Unit Operating Cost Rates: apply the rate adjustments identified during a calendar year to the UOCR for the immediately preceding year, and recalculate royalty for the preceding production year at a summary level. This royalty recalculation will charge or credit all royalty clients of record during the year based on the change in UOCR.

It is anticipated there will be two and only two adjustments made to the UOCR and the Capital rates for each production year. These adjustments (“13th months”) will occur at the mid-point and toward the end of the immediately subsequent production year. Filing deadlines for the necessary “13th month “ submissions are seen as being May and October of each year.

As each production year will see Crown royalties revisited and potentially restated on two occasions, provision must be made for recognizing refilings/audit adjustments to volumes and costs for the other prior years. These adjustments will be reflected in the “13th month” calculations for the year in which they are identified. e.g., 1996 audit adjustments identified in 1998 would be reflected in the restated 1997 capital and operating rates. In essence, the prior year’s rate adjustment will reflect current and prior years’ volumetric changes, current estimate to actual cost revisions, plus prior years’ cost revisions and any prior years’ audit changes.

In summary, relevant information filed or obtained during a year is used in calculating the “13th month” adjustments for the immediately preceding production year.

This mechanism would apply to both operating and capital cost rates.

Benefits

- Costs recognized in determining Crown royalty, properly follow the matching principle of accounting.
- Crown royalty charges/liabilities are updated for all known data on a current period basis.
- Adjustments are timely and reasonably predictable. Accruals, if required, are typically cleared within a year.
- Extreme fluctuation in capital and operating cost rates caused by mismatching costs and volumes is eliminated. This reduces confusion in royalty recording, accountability, budgeting, and forecasting for purposes of economic analysis, reserve accounting and property purchase or sale analysis.
- Financial impacts of “13th month” tend to fall on the current royalty owners, rather than on subsequent owners.
- Enables accurate accounting for Deep Gas Royalty Holiday program wells. Allowable costs have a significant impact on timing of pay-out and the ultimate benefit realization.
- Enables more accurate Freehold Mineral Rights Tax determination if, as recommended, the Mineral Tax program is delivered using business rules and processes similar to Crown Gas royalty.

Drawbacks/Concerns

- The recommended “13th month” approach does not totally eliminate the effect of prior year adjustments (audit or other) on future owners. As cost and volumetric revisions which occur beyond the point of one full year following the end of the production year tend to be reallocations the impacts are seen to be small. The alternative, using full “13th month” mechanics for each individual prior year is seen to have excessive administration for all parties.
- The necessary level of Crown royalty detail may substantially increase the size and/or complexity of the invoice containing the first and second (final) 13th month adjustments. Industry administration effort will be required to reconcile and validate the adjustments, some of which may be minor.
- The MRIS system must be physically capable of running the calculations within the allotted timeframe. The adjustments must be at a summary level of detail to make this practical.

There may be data storage/archiving issues, with attendant costs.

Custom Processing Cost Recognition for Crown Royalty Purposes

Situation with the Present Process

Custom Processing costs incurred in processing Crown royalty volumes are currently realized via a 13th month adjustment by way of the filing of the AC5. This annual filing advises of the total custom processing fees paid and volumes processed by facility. The Crown then claws back the UOCR deduction provided per Crown royalty volume each month and credits (or debits) the royalty payers subsequent invoice with the annual adjustment. The AC5 is widely held to be the most complex and difficult to prepare filing in the suite of Alberta Gas Royalty reports.

Options Reviewed

- Status Quo – AC5 with the associated submissions, restrictions and clawbacks.
- EUB facility level custom processing allowance consisting of facility's capital + operating rates.
- De-layered EUB facility level custom processing allowance consisting of capital + operating rates for each of gathering, compression and processing.
- Custom processing allowance attributable to gas type irrespective of processing facility used.

Analysis of Options

- The status quo is unacceptable due to the frustration and difficulty associated with the present accounting and filing requirements.
- Custom processors expressed strong concern over any custom processing allowance based on a facility's capital costs, as many plants are heavily depreciated, with little capital remaining, while most custom fees are based on replacement cost or assumed capital which is not allowed to depreciate beyond a certain rate.
- De-layering is undesirable due to the added complexity and administration, and attendant necessity for clawbacks.
- A clear and simple trigger to determine the status of a producer as custom processor or owner was desired.

Recommendation

Custom processing costs claimed via the annual AC5 filing will be terminated and a Custom Processing Allowance (CPA) established for Crown Royalty volumes of natural gas which are custom processed. The CPA will be determined based on the type of gas being produced. There will be a published CPA for each of sweet/dry gas and sweet/wet gas. In addition, natural gas identified as being sour (as per EUB directives) will receive a CPA equivalent to the plant type at which the custom processed volumes are processed. This in essence suggests there are 5 natural gas types. The types correspond to the existing 5 plant types. One for each of sweet/dry and sweet/wet and a CPA for each of the

3 plant types which handle sour natural gas (plant types 3,4 and 5). Each of the 38 designated facilities will be identified as one of the 5 plant types.

The CPA's for gas types are tied to the generic plant types as follow:

- Dry gas with dehydration and/or compression receives:
 - Generic Plant type #1 rate
- Wet gas with dehydration, compression and C3+ extraction receives:
 - Generic Plant type # 2 rate
- Sour gas receives:
 - Rate applicable to plant type processing the gas: 3, 4 or 5

The CPA's will:

- Include a capital and operating cost component.
- Be calculated based on the average operating and capital costs for each of the 5 plant types.
- Will be updated annually and adjusted through the 13th month process along with other Allowable Cost adjustments.

Intent

The intent is to set business rules that will fairly recognize the costs incurred for custom processing while eliminating the difficult administrative effort associated with tracking specific volumes and actual incurred costs.

Process

The existing EUB S-4 document will be modified by adding the ability to identify the destination gas processing plant and an indicator that the owner (royalty liability) has no ownership position in that gas plant. The CPA provided for custom processing would be the unit operating cost rate for that generic plant type plus the average capital cost rate for that generic plant type. The 38 designated facilities are, for custom processing purposes, identified as a generic plant type. Sour gas delivered for custom processing to one of the 38 designated plants will attract the CPA applicable to the appropriate generic plant type. Claims for excess capacity charges will no longer be recognized. The most significant impact of this is addressed by way of the move to distributing capital at an EUB facility level by way of valuation of the through-put.

Determination of Status: Is the gas custom processed and therefore eligible for the CPA?

A producer is deemed to be a Custom Processor (and thus eligible for the CPA) if the producer has no ownership in the gas processing facility. Ownership in one or more of the gathering and/or compressor facilities does not change this status. Conversely a producer owning capacity in a gas processing facility but with no ownership in the gathering and/or compression facilities is deemed to be an owner. As an owner, the producer would not be eligible for CPA.

Benefits

- Custom processing is the single most difficult and complex component of the current royalty regime. The proposed changes will significantly simplify this aspect.
- Eliminates the need to track custom processed volumes specifically for AC5 purposes.
- Eliminates the need to report custom processing fees and file AC5 claims with the Crown.
- Eliminates the form AC5 in its entirety.
- Eliminates the need for delayering operating costs and reporting delayered volumes.
- Is easily understood.
- Provides a capital component postage stamp even for fully depreciated facilities that recognizes the custom processor is levied such fees even in fully depreciated facilities.
- Use of averages provides for more consistent forecasting ability and economic analysis.
- Eliminates the contentious issue of excess capacity.

Drawbacks/Concerns

- There will be some redistribution.
- The allowance does not match the actual fees being levied on custom volumes.

Royalty Holidays

Situation with 1994 Regime

The purpose of the existing Deep Gas Royalty Holiday Program (royalty holiday) is to encourage drilling of successful, deep exploratory gas wells. The royalty holiday is given on actual production. The present system of administration cannot guarantee delivery of the legislated royalty holiday benefit.

The present system of Gross Royalty holidays was implemented in the 1994 royalty regime as a work-around rather than as a result of a desire on the part of Industry or the Crown for such a system. The work-around was necessitated by the 1994 regime's use of corporate capital deductions (CERR). As Net Royalty was no longer calculated at the well level, royalty holiday benefits were necessarily calculated on a Gross Royalty basis. In order to accomplish this a gross-up factor was introduced. The individual gross-up factor was based on one of the following:

- Wells with at least 3 year history – actual average relationship of gross to net royalty
- Wells with no history or inadequate history – transitional rules based on actual history
- Future wells – provincial average gross-up factor

Results were as follows:

- Wells with historical gross-up factors: Although in theory the net royalty holiday benefits realized were to equal the legislated benefits (net dollars) changes in corporate effective rate (CERR) and volumes caused some variances.
- Wells with no historical gross-up factors: ADOE and industry have not yet been able to finalize calculations of all gross-up factors, due to uncertain data and complex calculations.
- New wells: Although the gross-up factor is known, the actual benefits delivered by this system may differ significantly from the approved holiday amounts. If incurred gathering, compression and processing costs are higher than provincial average costs, significant loss of benefits may result. (Likewise, if actual costs are lower, excess benefits will be received).

Situation with Proposed Regime

The discontinuation of the Corporate Effective Royalty Rate eliminates the need for the 1994 work-around. As net royalties are again to be calculated at the well level, it is simpler, and more accurate, to revert to net royalty holidays.

Recommendation

Deep Gas Royalty Holiday Program benefits should be delivered on a net royalty basis with the introduction of the royalty/business rules which eliminate use of Corporate Effective Royalty Rate. Transition rules will be required for those wells earning and receiving benefits at the time of the transition. Wells not yet then on production would be advised of the reversion to the net royalty holiday benefit.

This recommendation is dependent upon the elimination of Corporate Effective Rate and corporate pooling of allowable capital costs.

Benefits

- Eliminates variance of received benefits from legislated benefits.
- Eliminates a work-around that is no longer required, resulting in simpler administration.
- Eliminates reliance on a provincial average gross-up factor which may vary significantly from that appropriate to individual wells.

Costs

- MRIS costs to change procedure.
- Transition rules may prove complex.

Allowable Costs – Insurance

Situation

Insurance, other than loss of revenue insurance, is an Allowable Cost for purposes of determining Crown royalty. However, in the event of an incident where insurance claims are realized, the administration around the issue is extreme. Except for public liability insurance that is carried by the operator and invoiced through the joint account, insurance is the responsibility of each working interest owner. And each owner arranges insurance coverage or elects to self-insure. Both practices are common in the industry.

In order to claim the cost of such insurance as an Allowable Cost the operator must obtain specific details as to premiums for each WIO. This information would then be used to file the operating costs (38 designated facilities). As each facility has one operating cost rate, those parties self-insuring receive benefits (for Crown royalty determination purposes) based on expenditures by parties. As a result operators frequently chose not to recognize this particular expense for purposes of Crown royalty.

In the event of an incident where insurance proceeds are realized a number of varying situations can and do occur. For example, in addition to the situation where certain WIO's are self-insured, the level of deductible is another variable, as are matters such as replacement cost versus depreciated value coverage. Given these variances, and as the operator is required to file the necessary cost documentation, it is today necessary for the operator to canvass each WIO and get assurances as to particular situation of each WIO. It is a major chore for the operator and the Crown to determine the final results of an incident in terms of revisions to the facility's capital balance. Under existing business rules, the Crown must verify insurance claim entitlements, if any, for each owner. This is difficult for all parties and adds to administrative and audit costs. It is not the operator's responsibility to sort out the various aspects of each WIO's coverage and claim settlements nor are the WIO likely to share this information with the operator.

Recommendation

Revise the Allowable Cost rules to disallow insurance as an Allowable Cost for Crown royalty purposes.

Any costs associated with reconstruction/replacement of facilities, irrespective of insurance proceeds being received by any of the WIO's will be treated as normal capital costs and/or operating costs.

Benefits

- All owners are treated consistently regardless of how they deal with insurance of risk.
- Audit activity and administration expense by the Crown is reduced.
- Business rules are simplified, and accounting for insurance costs and recoveries for Allowable Costs purposes is eliminated.

Drawbacks/Concerns

- Reduction of Allowable Costs for industry for insurance premiums paid.
- Potential increase in costs for the Crown for reconstruction where insurance proceeds were realized.
- The two impacts above may not be equal, due to timing of losses and varying Crown interests.

Freehold Mineral Rights Tax

Current Tax Determination Process

Each working interest owner of a well with freehold production calculates and submits to ADOE a well head "unit value", for the freehold production. This value determination is done annually before February 5-8th. The calculation is done using either actual netbacks or reference prices and actual costs or postage stamp allowable costs. Industry is directed to be consistent in their application of these options. For example, at a facility where the allowable operating plus capital costs are greater than the actual costs, industry may only use the allowable cost method at that facility if they use it everywhere and are consistent year to year.

ADOE averages all unit values at the title level and calculates the tax taking in to consideration net well head unit value, productivity and the taxpayer's interest in the title and well. A tax reduction is applied after determination of the gross tax. Given production sensitivity and the value of the tax reduction the assessed tax tends to range from 5-7% of net wellhead revenue derived from the freehold lands. In establishing the net tax payable, title owners each currently receive a \$1,600 tax reduction per taxable mineral right (that is for oil and for gas right) per title. There may be many owners for a title that supports only one or part of one well, or there may be one title covering the lands supporting many wells. Under the current system the tax reduction is title owner driven as compared to being sensitive to volume of production or value generated by the taxable mineral right.

Freehold Mineral Rights Tax Billing Process

ADOE annually bills (approximately Feb. 20) each mineral tax title owner for the annual Freehold Mineral Rights Tax. Copies of the tax details and the tax billing go to parties who have a declared interest in the title. While the Freehold Mineral Right Tax is billed to the title owner, the actual remittance and contractual responsibility for payment of the Freehold Mineral Rights Tax is shared between the mineral right owners and the working interest owners in a variety of ways. A typical example would see the Freehold Mineral Rights Tax paid in proportion to the freehold royalty rate. If the royalty is 12.5% of net well head revenue, then the freehold tax is paid 1/8th, 7/8ths. In other situations, the royalty owner carries no Freehold Mineral Rights Tax responsibility as the working interest owners have assumed all such responsibility. These obligations are as established in the freehold lease.

Actual tax remittance takes place in a number of ways. The method employed tends to be driven by the number of working interest owners and titles attached to a particular well, who the freehold mineral right owner is and how they want to do business. Working interest owners in a well may remit in full and then bill their partners for their share of the tax. Each working interest owner would subsequently deduct their respective freehold royalty owner's share of the Freehold Mineral Rights Tax from his monthly freehold royalty payment statement. This assumes that the freehold owner has not insisted on directly paying the proportionate share or all of the Freehold Mineral Rights Tax.

Audit – Compliance and Assurance

ADOE performs audits of the unit value submissions. There are two substantive components to the unit value calculation: revenues and Allowable Costs. The exercise of taking actual revenue streams and actual costs back to an individual well/title is seen as onerous and consequently many of the larger companies have begun to use Reference Price and the existing Allowable Costs. As noted above this is not a title specific decision. Industry has been advised that the Crown will only accept the use of operating and capital Allowable Costs if this method is consistently applied/used property to property and year to year.

Appeals and Adjustments

Freehold Mineral Rights Tax assessments can be appealed. The leading causes of appeals are industry review by industry of unit values, industry submission of a unit value to replace the default value and flare gas/fuel not being identified prior to the global tax run.

Proposed Process

ADOE calculates Freehold Mineral Rights Tax each month as part of the gas royalty invoicing process. This would entail using appropriate low productivity allowances, allocated volumes of segregated product, freehold percentage interests, reference prices (including client's annual sulphur corporate average price), the appropriate Allowable Costs and a tax rate set to generate a predetermined percentage of the net wellhead revenue derived from a particular freehold property.

Working interest owners would be responsible for initial remittance of the tax and the process of settlement with the freehold royalty owners would become part of the freehold royalty payment process.

The current tax reduction of \$1,600 per mineral title owner per taxable mineral right would be revised so as to a per-well deduction. This would entail some redistribution. The amount of the tax reduction may change from the current amount so as to ensure neutrality.

Petroleum Mineral Rights Tax

The Petroleum Freehold Mineral Rights Tax process would remain unchanged with the exception that petroleum mineral right owners whose property produces solution gas would see monthly Freehold Mineral Rights Tax invoices for solution gas and annual invoices for petroleum.

Recommendation

- Incorporate the calculation and billing of the gas component of Freehold Mineral Rights Tax into the Crown gas royalty process.
- Disable the gas portion of the existing system and continue to run the petroleum portion.
- The petroleum portion could be merged with the petroleum royalty system as and when feasible.

- All business rule changes recommended in this report and which are subsequently approved for implementation, including the use of 13th month adjustments, Custom Processing Allowances, and allocation of capital at an EUB facility level, are to be made business rules for purposes of calculating and invoicing natural gas Freehold Mineral Rights Tax.

Benefits

- All Crown charges on Alberta produced natural gas delivered in concert.
- Elimination of unit value calculations and submissions for gas.
- Elimination of seasonal ramp-up for special project staffing.
- Elimination of all audit activity specific to freehold gas production.
- Sharp reduction in appeals and adjustments.
- Elimination of industry's practice of 're-invoicing' a working interest owner's share of tax on certain titles.
- Elimination of large annual adjustments to freehold royalty owners to reflect recovery of proportionate share of Freehold Mineral Rights Tax as submitted by working interest owners.
- Elimination of second processing of production volumes by ADOE – once for Crown royalty each month, and again for annual Freehold Mineral Rights Tax calculation.
- No impact on tax status for freehold royalty owners. (Tax is still a tax on mineral rights, not a production tax, preserving Resource Allowance benefits).
- Titles receive tax reduction on the basis of economic units (i.e., wells).
- Elimination of tax avoidance efforts by title splitting, certain types of unitization etc.

Costs

- MRIS costs to change procedure.

Facility Pipeline Reclamation Costs

Situation

Joint venture accounting policy holds that only costs actually incurred can be billed to partners, thus accrual of reclamation costs is the responsibility of each joint owner and does not affect, nor is it reflected in the joint account.

Owners of processing facilities are liable for the costs of environmental reclamation of plant sites, compressor sites and pipeline rights of way. Cash expenditures on reclamation activity may occur over the useful life of the facilities however the bulk of the expense is incurred after all or part of the facilities have ceased operations. Costs are extremely difficult to predict and tend to rise over time as public expectations and governmental environmental regulations become ever more stringent. There are those who suggest that the Crown, previous owners and parties using the facilities on a Custom Processing basis also may have certain environmental liabilities/responsibilities.

Accounting theory holds that owners of such facilities accrue some recognition of the liability for this eventual cash expenditure. This theory is based on accounting matching principle that says 'end of life clean-up costs' are attributable to some or all of the production periods which gave rise to the pending expenditure.

Reclamation costs incurred during the productive life of a natural gas processing facility are recognized as direct costs by the joint agreements. In those situations, where reclamation costs are incurred after production ceases, there is no production stream and therefore at best a minimal revenue stream to fund the expenditures.

Reclamation and Abandonment cost recognition by the Crown as Allowable Costs for purposes of determining Crown royalty is less clear. In order for such expenditures to be recognized as Allowable Costs, policy work, including stakeholder consultations need to be held.

Should it be determined that the Natural Gas royalty rates were established anticipating the Crown sharing in reclamation and abandonment costs, then the necessary mechanisms would necessarily be established. As custodian of the natural resources of the province, ADOE would at best look to mechanisms that recognized cash either as spent or as deposited to a trust account that was limited in future to designated activity. One such possible mechanism would be allowing (recognizing) the reclamation costs when incurred to create a negative royalty, thus generating a cash payment to the royalty payers as work progressed. A mechanism that would not be acceptable to the people of Alberta would be to allow a straight accounting accrual that resulted in reduced Crown royalty even though no reclamation or abandonment work had been completed.

Irrespective of the outcome of the discussions on whether or not Crown royalty rates were set such that reclamation costs would be considered in determining net royalty, Alberta is concerned about the ever increasing liability. There is a real possibility that many producers will not be in existence or solvent when particular facilities cease production. As has been evidenced by the need for the Orphan Well Fund, the 'right thing' is not assured of being done. Establishing physically attached cash reserves, dedicated to environmental reclamation may reduce the public's concern.

As facilities age, the risk of being left "holding the bag", responsible for all reclamation costs, increases. If reclamation/abandonment costs are greater than predicted, previous

owners may have been subsidized by the final owner(s). With the exception of the degree of predictability of such costs, and bearing in mind the increasing environmental rigor expected by society, such 'subsidies' can be minimized by way of adjustments on closing and through the courts.

Possible Recommendations/Outcomes

- Site reclamation/abandonment work is not seen as an expense incurred in order to gather, compress or process Crown lease sourced natural gas.
- Allow actual costs of reclamation and abandonment with royalty credit to the existing royalty paying facility owner.
 - Matches timing and liability of payment.
- Allow a deemed environmental reclamation accrual in each production year to match the eventual cost associated with each production period.
 - Matches production periods but not actual liability.
- Allow voluntary cash contributions to an environmental reclamation trust account.
 - Matches production periods and liability for estimates, but does not address major discrepancy of actual costs when incurred.
- Regulate cash contributions to an environmental reclamation trust account.
 - Matches production periods and liability for estimates, but does not address major discrepancy of actual costs when incurred.

Recommendation

The Crown and Industry immediately begin an exercise whereby the question of environmental clean-up (plant / facility decommissioning and general abandonment) costs be investigated and consideration be given to recognizing such costs for Crown royalty determination purposes.

Mitigating Strategies

Background

The general guideline given to the task force is:

There will be minimal royalty quantum change and the Department will consider the implications of royalty redistribution.

As each business rule or process is changed and while quantum is held relatively constant, royalty re-distribution occurs. This section identifies the tools available and the strategies and actions that may be used by the Crown to mitigate the effects of such redistribution.

As decisions and recommendations are made, certain of the potential intervention tools become less viable. This section also includes a listing of the tools that have been *parked* at various times throughout the investigation. This suggests the parked tool is unlikely to be of significant benefit in addressing the nature and type of situation that may require intervention.

Options

Given the extent and nature of the Crown royalty re-distribution that model 20 generates, the following methods of intervention are seen to be the most effective mitigation strategies available:

- Suspend minimal royalty charges on monthly/annual basis.
- Top-up specific facility capital balances.
- Lead time/ timing of implementation date of recommendations.
- Align Allowable Costs eligibility with industry accounting standards.
- Provide annual CAP/reference price election for royalty payers paying less than \$30,000 per year.
- Consider the identified re-distribution in the upcoming ARTC program review.
- Consider wins/losses arising from Gas Simplification 1994.

Each of these potential tools has implications that warrant consideration

Implications

Suspend minimal crown royalty/tax charges monthly/annually

This option requires:

- Legislative changes – Crown royalty, freehold mineral tax and Alberta Royalty Tax Credit.
- Identification of program inter-dependencies: business rules and processes, source data.
- MRIS system upgrades and impacts on other platforms.
- Provision for regular correspondence to advise liable party/Treasury of status.
- Solid business associate rules.
- Appreciation of impact on the size of existing royalty payer list (1993 750 and 1996 1,800).
- Clarity of rules as to *suspension* of payment of the charges versus forgiveness, write-off.
- Legislative co-ordination to ensure ARTC benefits are driven by royalties actually paid versus royalties calculated.

Top-up of specific facility capital balances

This option requires:

- Appreciation that *benefits* also accrue to royalty payers not negatively impacted by regime changes.
- Appreciation of the need to present value the *top-up* to compensate for return allowance.
- Substantiation of the rationale for the point at which no further mitigation occurs.

Lead time/timing of implementation date of recommendations

This option requires:

- Appreciation that no further mitigation activity is required.
- Recognition that the cause of the losses in the proposed regime was the cause of *wins* in 1994.

Align allowable cost eligibility with industry accounting standards and practices

This option requires:

- Appreciation that pressure will mount to make rules retroactive.
- Need to establish standard percentages to address the proportionate share of partially ineligible costs.
- Recognition that the Crown will see increased costs to process Crown royalty volumes.

Provide annual prospective election of corporate average price/reference price for royalty below \$30,000 per year

This option requires:

- Recognition of increased administration cost for the Department of Energy and those selecting the CAP option.
- Appreciation that pressure will mount to increase the dollar level at which the option is available.
- Business rules committing CAP filers to election implications irrespective of amendment impacts.

Consider projected gains/losses in the context of Gas Simplification 1994 and upcoming ARTC review

This option requires:

- Appreciation and understanding that Alberta Royalty Tax Credit program is Crown royalty dependent.
- Appreciation and understanding that the cause of many 1994 *wins* is the cause of most projected losses.
- Legislative updates to ensure benefits under the ARTC program, or its successor, are based on royalties paid.

Conclusion

- The negative distribution caused by the proposed business rule changes (most notably by the move from Corporate Effective Royalty Rate to an Energy Utilities Board Facility Effective Royalty Rate) amounts to approximately \$45.6 million with a transfer of \$22.8 million. This number does not include any provision for increased Allowable Costs driven by the recommendations to take decisions on reclamation/abandonment and to align gathering, compression and processing Allowable Costs with PASC standards. Nor does it include the *cost* to the Crown in foregone royalty driven by the recommendations to suspend invoicing/collection of minimal royalty/tax balances and the reference price/corporate average price election (royalty payers of less than \$30,000 per year).
- Top-up of capital at the most significantly impacted facilities addresses the cause of the distribution (move from Corporate to Facility Effective Royalty Rate). These facilities tend to have high levels of custom processed and/or freehold throughput. The facilities in question tended to be the winners in 1994 because of the move to Corporate Effective Royalty Rate to make compensation for the reversal unnecessary.

Additional Mitigation Tools

The following list contains suggested intervention tools that at this point have been identified as being ineffective given the nature and extent of the distributional impact that may need to be addressed.

Parked Tools

The tools below, detailed in Appendix C, have been parked.

- Solution #7 Eliminate/adjust vintage
- Solution #13 Write-off remaining capital balances
- Solution #20 Set separate Crown royalty rates for different products allowing for Allowable Costs
- Solution #21 Introduce third tier natural gas royalty rate.
- Solution #27 Operator pays Crown charges when acting as marketing agent for some or all working interest owners
- Solution #29 Remove royalty treatment differences between gas plant and field pentanes

Additional Tools

- Revisions to low productivity parameters
- Accelerated depreciation
- Change recognized rate of return on capital investment
- Changes to performance requirements regarding Crown licenses/leases
- Changes to EUB fees and assessments
- Changes to Department of Energy fees/charges including annual rentals
- Transportation allowances – natural gas or liquids
- Transition strategies that recognize increased costs of compliance, i.e., methodology for assisting industry to acquire equipment capable of timely wellhead effluent measurement and reporting
- Royalty rate applied to specific Crown royalty volumes could be revised
- Remove (perhaps enhance) holiday and special case benefits
- Crown charges paid on time lines other than monthly (limited applications)
- Revise EOR capital/operating cost claw back rules and processes
- Ring fencing of and provide special treatment to unique cases
- Revisit the Crown's position on reclamation/abandonment cost recognition
- Phase-in of business rules
- New regime features, i.e., sulphur productivity allowance, SECAP

Capital Investment Risk for Software Vendors

Issue

The current business relationships between software vendors and their clients represent a risk to the successful implementation of a complex software solution to royalty and reporting problems.

Background

Most solutions discussed to date involve a heavy IS/IT investment, especially in the development or modification of software. This investment must be made far in advance of the anticipated implementation date of the new regime. Those producers who maintain their own IS/IT staffs will begin investing in software to meet the new requirements in advance of the expected implementation date. However, those producers (by far the large majority) who choose to use solutions created by the software vendors have historically assumed that the software vendors will make the capital investment in advance and will assume all of the risk of change prior to implementation. The traditional business relationship between the software vendors and the producers has been that software change brought about by change in *legislated reporting requirements* is provided under terms of maintenance agreements and, therefore, has been funded by the vendors. When the legislated changes require a major software re-investment, recovering this investment from maintenance charges is very slow and risky.

The vendors should be viewed as companies who have a finite amount of money to invest in the creation of software products, but **not** necessarily the product required by the new royalty regime. When viewed in this light, it is apparent that the vendor may choose to invest somewhere other than in the royalty regime if, in the judgment of each vendor, the risk associated with the investment is too high.

Contributing Factors

- Relatively few vendors service a relatively large segment of the industry. A decision by even one of them to drop out of the game causes a significant gap. Even if the remaining vendors can fill the gap, this results in the concentration of services in fewer vendors and some significant migration issues for those producers who must switch to a different vendor.
- Migration issues surface when a producer decides to switch software vendors. Most vendor systems are built on proprietary data and process models. Each solution is sufficiently different in granularity of data stored that it is almost impossible to change vendors and convert all the producer's historical transactions and fixed data. This potential loss of historical data, combined with training issues and long implementation times, is a tremendous barrier to switching vendor systems.
- Due in part to the migration issues, the relationships between producers and vendors tend to be long term, sometimes up to 8 or 10 years before a producer decides to review systems. The risk is that if a vendor decides not to provide the

new royalty regime for clients, all of that vendor's clients are forced into these migration problems.

- A long implementation period (from the decision to the initial reporting under the new regime) increases the risk of:
 - A change in business rules. The cost of these changes is significant. For example, in the recent change from the old to the new gas royalty reporting and invoicing system, one vendor has estimated a total unrecovered expense of \$1.6 million, made up of:
 - \$400,000 for the programming of the OAS form,
 - \$400,000 for programming of the Crown estimate functionality, and
 - \$800,000 for programming of the Crown invoice.
 - All major vendors agree that each one has invested multi-millions of dollars into their systems. The capital investment for Royalty Simplification 1 (OAS, Crown Estimating module, Crown Invoice Reconciliation and Booking module) will probably never be recovered by some. In fact, costs are still occurring due to continuous change to the government-supplied invoice UDF file.
 - Changes in client base. The vendors must make the decision to invest before they have certainty that their client base will purchase their product. Current merger and acquisition activity has reduced the size of the overall market.
 - Changes in technology. The increasing pace at which new technology reaches the market and the desire of clients to own and use newer technology forces a relatively short system life cycle. These short life cycles are tolerable if an *off-the-shelf, shrink-wrapped package* of software is being purchased. Production/royalty accounting software is complex and usually interfaces with mission critical applications such as field data capture, land and financial; changes to the interfaces and the associated risk to the producer are significant.
 - Legislated changes in other jurisdictions, requiring software changes to be undertaken and completed during the implementation schedule for Alberta changes.
- A short implementation period assists, but does not necessarily eliminate, the risks mentioned above. In addition, planned short implementation time frames have associated risks of their own (i.e., availability of staff, last second changes in rules), which are liable to increase the planned short time frame to something longer.

Mitigating Strategies

- Producers and vendors jointly fund the capital investment needed to create the software. For this to happen, a new business arrangement needs to be negotiated between producers and their vendors.
- Staged implementation whereby a smaller capital investment is required by the vendor and can be recovered sooner in order to fund the next stage of implementation.

- Ensure that business rules are fully confirmed, tested and able to be implemented before release by the government. Once released, the government can assist the vendors and producers by freezing the rules for a time.
- Very tight control by the government of any changes required and a full understanding of the impact of each change on client software systems to allow sufficient lead time to properly implement and test the change.
- Provide as much training and information as possible to all producers early in the process. Educate producers as to the potential business impacts rather than have the producers rely on the software provider to relay business impacts second hand.
- Recommendations and new business practices that may be suggested by this project team have a better chance of gaining widespread use if they are regulated. Few producers look beyond the regulated mandatory changes to change their underlying business processes, even if the option exists at no additional cost within the software and will be beneficial to the producer.

Conclusions

- Based on past history, the cost of change in royalty business practice is high. The business relationship between vendors and their clients is inappropriate to the recognition of this cost.
- Producers should anticipate that the vendor stakeholder group will behave in a different fashion than they have previously.
- The government stakeholders can assist by implementing strict change control mechanisms and solid business rules. The government can anticipate a request to freeze these rules for a time period after implementation.
- Industry can assist in mitigating this risk by pro-actively approaching their individual vendors to discuss the business relationships.