Alberta Oil Sands Royalty Guidelines

Principles and Procedures

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Alberta ENERGY

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Notice

The guidelines outlined in this document are based on the *Mines and Minerals Act, RSA 2000,* c. M-17, as amended, and the *Oil Sands Royalty Regulation*, *1997* (AR 185/97), as amended. The Act, the regulations and the guidelines themselves are subject to regular reviews by the Department of Energy. They are amended as required, in response to changing circumstances and business needs.

These guidelines reflect Department of Energy policies and procedures as of January 31, 2005. Industry will be notified when the guidelines are revised.

The *Alberta Oil Sands Royalty Guidelines* are produced for the convenience of readers. The guidelines provide a general understanding of the principles used to establish oil sands royalty legislation. They explain the administrative policies used by the Department of Energy in interpreting this legislation. They also explain the business rules and operating procedures used when royalty-related legislation is applied.

> Readers are reminded that the guidelines have no legislative sanction. Should the guidelines conflict with the *Mines and Minerals Act, RSA 2000,* c. M-17 or the *Oil Sands Royalty Regulation*, *1997* (AR 185/97) the Act and Regulation will prevail.
>
> To the extent that the guidelines conflict with any previously published Department of Energy Information Letters on any subject matter contained in the guidelines, the guidelines will prevail.

The Act and the Regulation

Copies of the *Mines and Minerals Act*, the *Oil Sands Royalty Regulation, 1997* and related legislation are available through the Queen's Printer:

In Edmonton:	E-mail: qp@gov.ab.ca
Main Floor • Park Plaza	Web Site: http://www.qp.gov.ab.ca/index.cfm
10611 – 98th Avenue	
Edmonton, Alberta T5K 2P7	
Phone 780.427.4952 • Fax 780.452.0668	

Free, online copies may be downloaded from the websites of the Queen's Printer or the Department of Energy.

For information or inquiries regarding the guidelines, please contact the appropriate Department representative listed in Appendix J, "Contact Information".

Related Legislation

The following legislation applies to specific aspects of oil sands development and administration:

- *Mines and Minerals Act, RSA 2000, c. M-17*
- *Mines and Minerals Administration Regulation (AR 262/97)*
- *Oil Sands Tenure Regulation (AR 50/2000)*
- *Oil Sands Royalty Regulation, 1984 (AR 166/84)*
- *Oil Sands Royalty Regulation, 1997 (AR 185/97)*
- *Petroleum Royalty Regulation (AR 248/90)*
- *Experimental Oil Sands Royalty Regulation (AR 347/92)*
- *Oil Sands Conservation Act, RSA 2000, c. O-7*
- *Oil Sands Conservation Regulation (AR 76/88)*
- *Natural Gas Royalty Regulation, 2002 (AR 220/2004)*
- *Innovative Energy Technology Regulation (AR 250/2004)*

About This Document

The *Alberta Oil Sands Royalty Guidelines* were developed by the Alberta Department of Energy through a consultative process that included oil sands industry representatives. The guidelines are designed to

- interpret relevant oil sands legislation
- communicate oil sands royalty-related policy to industry stakeholders
- help oil sands developers determine and calculate the share of royalty payable to the Crown
- make it easier for the oil sands industry to comply with the requirements of the *Mines and Minerals Act* and the *Oil Sands Royalty Regulation*, *1997* (AR 185/97)

Conventions used in this document

The Minister refers to Alberta's Minister of Energy.

The Department refers to the Alberta Department of Energy.

The Act refers to the *Mines and Minerals Act*.

Unless otherwise stated, **the Regulation** refers to the *Oil Sands Royalty Regulation, 1997* (AR 185/97).

The terms **generic**, **generic oil sands royalty** and **generic oil sands royalty regime** refer to the royalty calculation and collection methodology outlined in the Regulation.

An **oil sands royalty project (OSR project)** is an oil sands project for which royalty calculation and reporting is governed by the Regulation.

Chapters and Appendices

The Alberta Oil Sands Royalty Guidelines address a number of areas:

- Chapter 1 - looks at the evolution of Alberta's oil sands royalty system and provides an **overview of how the current, generic oil sands royalty regime works**.

- Chapter 2 - explains the requirements for oil sands royalty projects.
- Chapter 3 - describes the process of applying for **generic oil sands royalty terms** under the provisions of the *Oil Sands Royalty Regulation, 1997* (AR 185/97).
- Chapter 4 - is an introduction to **oil sands royalty calculation**.
- Chapter 5 - defines the **specific cost allocation rules** that relate to solution gas and fuel gas, pipelines, cogeneration plants, custom processing, hedging and research.
- Chapter 6 - describes the requirements for **royalty reporting and payment**.
- Chapters 7 and 8 - deal with **advance rulings** and **dispute resolution and appeals** respectively.
- Chapter 9 - provides **definitions for accounting concepts** such as affiliates, fair market value and non-arm's-length transactions, and explains how these concepts apply to oil sands royalty calculations.

The appendices include

- a glossary
- a sample of an oil sands project approval order
- **forms** used for oil sands royalty reporting
- list of acronyms & definitions
- contact information
- figures contained in guidelines (with additional footnotes)

Additional Information

The *Alberta Oil Sands Royalty Guidelines* presume the reader's familiarity with the geography and development history of Alberta's oil sands, as well as their strategic importance to the province's economy. The guidelines also presume the reader's familiarity with the technology and economics of oil sands production and with the Alberta tenure system through which Crown-owned oil sands rights are leased and administered.

Readers who need additional information are referred to the Department of Energy website at <www.energy.gov.ab.ca> under 'Our Business', then 'Oil Sands'.

1. Alberta's Oil Sands Royalty System

The Alberta Crown owns 97% of oil sands mineral rights; freehold owners hold the remaining 3%. Mineral rights owned by the Alberta Crown are managed by the Department of Energy on behalf of the citizens of the province.

Oil sands tenure is the system through which Crown-owned oil sands rights are leased and administered. Alberta's tenure system generates revenue by granting the right to produce oil sands products.

Oil sands royalty is the system through which the Crown—as the owner of the province's oil sands—receives a share of the economic rent generated from the development of that resource. The Alberta Crown receives a royalty—a share of recovery of oil sands products or equivalent revenue—from its oil sands rights leased to oil and gas companies.

1.1 Oil Sands Royalty: A Look Back

In the 1960s, when the first commercial oil sands projects were launched, oil sands development was a very costly, high-risk exploration of unknown frontiers. A lack of facilities and lack of technology meant developers faced formidable challenges in extracting bitumen.

To encourage the development of the oil sands industry in the face of these early challenges, the Alberta government adopted a royalty regime in which the Crown shared the risk by providing developers with direct benefits and subsidies. Royalty terms for significant oil sands projects were negotiated on a project-by-project basis and specified in individual Crown agreements. Minimum royalty rates on gross revenue ranged from 0% to 5%. Royalty on net revenues ranged from 25% to 50%. Specific development, operating and capital costs were allowed and some gas royalties were waived.

A project-by-project approach to royalty made sense in the formative years of the oil sands sector. It allowed for flexible royalty arrangements to accommodate the unique requirements of each project and address project-specific concerns. It was manageable because there were few commercially active operations. And it helped to build a body of knowledge and experience that formed the basis of current oil sands legislation.

As oil sands development advanced, research and technological innovations contributed to the development of new tools and processes that increased returns on investment and reduced production costs. More companies got involved in oil sands development and world oil prices and global market forces governed their investment decisions. A different royalty regime was needed to address the different circumstances and needs of a growing oil sands sector.

1.1.1 The Impetus for Change

In 1993 the joint, industry–government National Task Force on Oil Sands Strategies was launched to assess the technical, socio-economic, environmental and marketing aspects of oil sands development and recommend strategies to address these issues.

The task force identified Alberta’s ad hoc, project-specific royalty structure as a barrier to oil sands development. The ad hoc structure created uncertainty about what royalty terms would apply to future investments, because the royalty terms had to be negotiated for each new Crown agreement. In addition, since the royalty structure was not transparent, it was difficult for developers to evaluate investment plans.

In its 1995 report the task force outlined a comprehensive, new royalty approach for Alberta’s oil sands industry. A key recommendation was that royalty should be established through legislation rather than individual Crown agreements. That is, the royalty regime should be generic: the same rules should apply in the same situations and the same clear, standardized royalty terms should apply to all new oil sands projects. The task force believed that a generic approach to oil sands royalty would place all new projects on a level playing field. Standard royalty terms would create fiscal certainty and stability, and encourage oil sands investment.

The Government of Alberta accepted that recommendation of the task force and began work to develop legislation and policy to support a generic oil sands royalty regime.

1.2 Generic Oil Sands Royalty

Alberta’s current, generic oil sands royalty regime dates to July 1, 1997, when the *Oil Sands Royalty Regulation, 1997* (AR 185/97) came into force.

1.2.1 What Is “Generic” Royalty?

The current oil sands royalty regime was dubbed generic because the same, standard royalty rates and rules apply to all oil sands projects approved under the regime. The royalty rates are established through legislation rather than individual Crown agreements. The rates are the same for all new oil sands projects and are not subject to negotiation.

1.2.2 A “Revenue Minus Cost” Approach

Alberta's project-based generic oil sands royalty regime operates on the principle of revenue minus cost. Royalty is paid at one of two rates, depending on the project’s financial status. The deciding factor is the project’s **payout date.**

A project has “reached payout” once its cumulative revenues have exceeded its cumulative costs.

Before the payout date, the applicable royalty is 1% of the project’s gross revenue. This low rate recognizes the high costs, long lead times and high risks associated with oil sands investment. It prevents undue strain on the developer's financial resources during the most critical, start-up stages of the project.

After the payout date, the applicable royalty is the greater of

- 1% of the project's gross revenue, or
- 25% of the net revenue for the period

This feature of the generic regime links the Crown's return to the success of the project. The Crown does not receive a significant share of royalty until the project is off the ground and profitable and the developer has recovered his investment. This approach encourages developers to innovate and maximize the efficiency of their operations.

Reaching Payout: What Are the Implications?

When an oil sands royalty project reaches payout, its **royalty rate** and **reporting obligations change**. In addition, the post-payout royalty rate is variable. For example, if revenues drop off or if expenses increase as a result of an approved expansion, the "1% of gross revenue" rate might apply even if a project had reached payout in previous years. Royalty payment at 25% of net revenue would recommence when it exceeds 1% of the project's gross revenue. **NB: Once a project reaches payout it is always considered to be in payout, even if it pays royalty at 1% of gross revenue for some period of time.**

Definition of a "Period"

A period is defined in the Regulation as each calendar year, or partial calendar year that occurs between the effective date of a project and the date the project approval is revoked.

Additionally, since a project typically reaches payout during the calendar year, the portion of the calendar year before the payout date and the remainder of the calendar year following the payout date is considered separate periods.

Periods include only full months. The effective date of a project is normally the first day of the month. Likewise, a post-payout period always begins on the first day of the month in which payout occurs.

1.2.3 Objectives

Alberta's royalty systems are designed to maximize and capture a fair share of the value of mineral and energy resources for the benefit of Albertans.

——*Alberta Energy Business Plan*, 2003–2006, p. 123.

Alberta's generic oil sands royalty regime provides a stable, competitive fiscal framework that supports the major investments needed to develop the province's oil sands resources. The regime is designed to:

- encourage the development of the oil sands while ensuring a fair return to Albertans, who own the province's resources.
- create a stable fiscal and regulatory framework that facilitates oil sands development by private sector companies;
  - development occurs because investors expect to make a reasonable profit from oil sands ventures. The Government of Alberta does not provide grants, loans, loan guarantees, or any other "special deals" to encourage oil sands investment.
- ensure that investment in the oil sands provides a rate of return that is competitive with other petroleum development opportunities around the world.

1.2.4 Applicability: Who Pays Generic Royalty Rates?

Oil sands developers who wish to pay royalty at the generic royalty rates **must apply to have their projects approved as oil sands royalty projects** under the provisions of the Regulation. (see Chapter 3, "Applying for Generic Royalty Terms)"

1.2.5 Components of the Generic Royalty Regime

Alberta's generic royalty regime includes three components:

- the Mines and Minerals Act, RSA 2000, c. M-17
- the Oil Sands Royalty Regulation, 1997 (AR 185/97)
- policies, guidelines and business rules

1.2.5.1 The Mines and Minerals Act

The *Mines and Minerals Act, RSA 2000,* c. M-17 was amended in May 1997 to embed oil sands royalty formulas and core rates in legislation:

- *Sections 33 to 39* of the Act outline general provisions related to royalty.
- *Sections 87 to 90* relate specifically to oil sands. Section 90(2) specifies that the "royalty reserved to the Crown … during each month of a pre-payout Period" is 1% of gross revenue. *Sections 90(3)(a)* and *90(3)(b)* specify that the "royalty reserved to the Crown … during a post-payout Period" is the greater of 1% of gross revenue or 25% of the project's net revenue.
- *Section 90(6)* outlines the allowed return allowance payable on allowed unrecovered balance of cumulative costs less cumulative revenues.

Details about royalty calculation are provided in Chapter 4," Calculating Oil Sands Royalty".

1.2.5.2 The Oil Sands Royalty Regulation, 1997 (AR 185/97)

The Regulation outlines the following components of the generic royalty regime. Each component is discussed in detail in the following chapters of the *Oil Sands Royalty Guidelines*.

- the "revenue minus cost" approach to oil sands royalty (Chapter 1)
- the components of an oil sands royalty project (Chapter 2)
- the administrative requirements for applying for, amending or approving oil sands royalty projects (Chapter 3)
- the revenues and allowed costs that are considered in calculating royalty (Chapter 4)
- specific cost allocation rules (Chapter 5)
- the requirements for royalty reporting and payment (Chapter 6)
- the procedures used to resolve disputes (Chapter 8)

1.2.5.3 Policies, Guidelines and Business Rules

The policies, guidelines and business rules used to interpret and implement oil sands royalty–related legislation are developed by the Department of Energy in consultation with the oil sands industry.

1.3 Alternative Royalty Regimes

Developers who do not apply for an oil sands royalty project approval under the Regulation pay royalty under one of the following regimes, as appropriate:

- the Oil Sands Royalty Regulation, 1984 (AR 166/84)
  - Royalty paid under this regulation will be calculated under the *Petroleum Royalty Regulation* (AR 248/90).
- Existing Crown agreements authorized by the *Mines and Minerals Act*
  - The owners and developers of pre-1997 projects pay royalty according to the terms of their Crown agreements.
  - The Crown will not enter into any new agreements.
- the Experimental Oil Sands Royalty Regulation
  - **No new projects will be approved under this regulation.** Experimental projects that were approved by the Alberta Energy and Utilities Board before August 1, 1997, may retain experimental royalty status for the duration of their designation as experimental schemes.
  - Project owners have the option of applying for project approval under the *Oil Sands Royalty Regulation*, *1997* (AR 185/97).

2. Oil Sands Royalty Projects

2.1 What Is an Oil Sands Royalty Project?

Under *section 10* of the *Oil Sands Conservation Act,* the Alberta Energy and Utilities Board (EUB) may grant an approval to a person to construct facilities for, or commence or continue, a scheme or operation for the recovery of oil sands or crude bitumen.

The EUB may also grant approvals for processing plants under *section 11* and industrial development permits under *section 12.*

These schemes or operations approved under *section 10* of the *Oil Sands Conservation Act* are often loosely referred to as oil sands "projects", but the term project has a specific meaning under the Regulation:

Projects Defined

> *Section 1(aa)* of the *Oil Sands Royalty Regulation*, *1997* (AR 185/97), defines an **oil sands project** as "a scheme or operation for the recovery within Alberta of crude bitumen or any other oil sands product from oil sands, whether or not in conjunction with the further processing of the crude bitumen or other oil sands product, where the scheme or operation is approved in one or more subsisting approvals under *section 16*."

A developer who wishes to pay royalty under the terms of the Regulation must apply to the Department. If the scheme or operation has been approved by the EUB, and if the project meets the requirements of the Regulation, it may be approved as an oil sands royalty (or OSR) project.

An OSR project approval is granted by Ministerial Order. The project approval order includes appendices and attachments that describe the project, specify its effective date and detail all related terms and conditions.

Department of Energy approval is required for all **new OSR projects**, as well as for all **significant amendments** to currently approved projects. (For examples of what constitute significant amendments, see 2.1.1.2.1)

A Note on Terminology

> The **project description** included as part of a project approval order specifies the lands, leases, operations, facilities and infrastructure that are considered to be "part of the project" or "in the project." In this way, it defines what revenues and costs are included in (or excluded from) the royalty calculation: only approved components are considered part of the project.
>
> The approved project description for a new oil sands royalty project is called the **initial project description**. When a project is amended, the approved description is referred to as the **amended project description**.

Details about the application and approval process are outlined in Chapter 3, "Applying for Generic Royalty Terms".

2.1.1 Types of OSR Projects

Oil sands royalty projects fall into one of the following categories:

- new projects
- amendments to approved oil sands royalty projects (including expansions and amalgamations)

2.1.1.1 New Projects

Projects are considered new if production has not yet begun or if royalty payment under the Regulation has not been previously approved. For example, oil sands operations that previously paid royalty under the *Oil Sands Royalty Regulation*, *1984* (AR166/84), are considered new when an application for approval as an oil sands royalty project is made.

When a new oil sands royalty project is approved, an attachment (schedule A) to the Ministerial Order outlines the **initial project description**, which specifies (at minimum)

- the **lands and leases** that have been approved as part of the OSR project
- the **project operations**, including the recovery method and technology that have been approved, the product that will be produced and, in some cases, the approved production capacity
- approved project **facilities** (including the required EUB approval orders) and **capital assets** (see 2.3.8, "Facilities and Capital Assets")

2.1.1.2 Project Amendments

Oil sands developers who wish to modify the terms of their project description in any substantial way must apply to the Department of Energy. If the application meets the requirements of the Regulation (under *sec 16(1)*), an amended project approval order may be issued. The approval order includes an amended project description.

Project amendment applications are required for

- **expansions**, which typically involve the addition of lands or facilities
- **amalgamations**, which combine two or more approved OSR projects into a single project unit for the purposes of royalty calculation
- other changes to the project description issued when the project or subsequent project amendments were approved

Project amendment applications are encouraged—but not required—when a project's operator is replaced or when changes are made to the working interest ownership. In these cases, the project operator must nonetheless notify the Department so that records and contact lists can be kept up to date.

Consulting with the Department

> Oil sands royalty project developers are encouraged to discuss **all proposed changes to their OSR project** with the Department to determine if a project amendment application is required or if what is proposed is consistent with the existing project approval order appendices, schedules and attachments.

2.1.1.2.1 Examples of Project Amendments

The following situations are examples of triggers or situations resulting in project amendments that need the approval of the Department. This is not meant to be an exhaustive list of triggers, but it should reflect most situations that require a project amendment. Again, if a operator is uncertain whether a particular situation would require an application, the operator should contact the Department.

- adding or removing lands, surface areas, geologic strata or oil sands leases from the project description
- changing the facilities or infrastructure used by the project, resulting in a change to the royalty calculation point or product
- adding or removing facilities that change the project scope for revenues or costs or both (e.g., a cogen plant, asphalt plant), but excluding situations where existing facilities are used to change the project output mix
- adding or removing facilities or infrastructure that are off project lands (i.e., facilities or assets that are not located within the project area, and not usually described in the EUB scheme approvals); for example, offsite batteries, roads, power lines, disposal wells, etc.
- changing a non-qualifying joint venture to a qualifying joint venture or vice versa
- changing project operations from the existing project description that include but are not limited to new phases and different recovery and extraction methods
- changing the project description as set out in the existing project approval order appendices, schedule and attachments

- changes to the EUB scheme approval (see note, below)

Note: When does a change to facilities or operations trigger an OSR project amendment?

> Changes related to project facilities or operations must be approved by the EUB. When an amendment to an EUB approval affects an oil sands royalty project project's recovery technology or processing capacity, the operator must apply to amend the OSR project approval order as well.
>
> If the amendment to an EUB approval is minor, an OSR project amendment may not be required. Examples of minor amendments include changes to the operator's name, original well spacing, land use or approval for in-fill drilling. **Operators should contact the Department** to determine if an OSR project amendment is required in such cases.

2.2 OSR Project Requirements

Both new oil sands royalty projects and OSR project amendments must meet the following requirements.

2.2.1 EUB Approval

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 17(1)(a)

For an oil sands operation to qualify for generic royalty treatment, as outlined in the Regulation, its production schemes, operations, processing plants, wells and facilities must all be approved by the Alberta Energy and Utilities Board, as required *under sections 10 to 15* of the *Oil Sands Conservation Act*.

Schemes, operations and facilities that do not have EUB approval cannot be approved as part of an oil sands royalty project.

EUB approvals must be filed with the Department as part of the application for OSR project approval. The required EUB approvals must be in place before an oil sands royalty project can be approved.

2.2.2 Exclusions

Any portion of the land, facilities or assets included in an EUB-approved scheme may be excluded from an oil sands royalty project description at the request of the applicant or at the discretion of the Minister.

Note

> Some types of capital assets used in an oil sands royalty project may require approval by agencies other than the EUB. It is the responsibility of the project operator to ensure that all necessary approvals are obtained.

2.2.3 Minimum Considerations

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)

The Department must, before issuing an oil sands project approval order (or amendment), consider, without limitation:

- Whether all project-related assets and operations are under **common management**.
- Whether all project components comply with the **location requirements** specified in the Regulation.
- Whether the project and all its components are **economically justifiable** and function as an integrated **economic unit**.
- The project's **impact to the royalty** payable to the Crown.

In issuing a project approval order, the Minister may take additional considerations into account, as warranted by the specifics of the situation. In all cases there is no specific weighting that would be applied to each consideration. The importance of each consideration may vary from circumstance to circumstance.

2.2.3.1 Common Management

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(a)

The Minister must consider whether all project-related activities, facilities, and assets are under common management. This does not mean that a project may not have various owners, but planning, management and operations must be integrated so that the project functions as a single unit for royalty calculation purposes.

2.2.3.2 Location Requirements

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(b), (c) and (e)

The Minister must consider whether all components of an OSR project comply with the location requirements specified in the Regulation.

2.2.3.2.1 Project Components (Except Upgraders)

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(c)

The Minister must consider whether, except for upgraders, any component of an OSR project is located more than 50 kilometres from any other component. That is, whether the two most distant points are no more than 50 km apart.

2.2.3.2.2 Upgraders

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(b)

Upgraders and the pipelines that connect them to other project components are not subject to the 50-kilometre restriction. However, the Regulation stipulates that the Minister must consider whether upgraders are located in Alberta.

2.2.3.2.3 Exceptions

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(e)

In exceptional circumstances, components located outside the 50-kilometre guideline *may* be approved as part of an oil sands royalty project. Such components will not be considered for inclusion unless the applicant can clearly demonstrate that all of the following criteria have been met:

- *The proposed out-of-project-area component must be "substantially geographically contiguous" with other parts of the project.*
- *It must be operationally integrated with the rest of the project.*
- *It must comply with the cost criteria specified in the Regulation.*
- *Including it as part of the OSR project description must provide significant economic and operational synergy.*

If these criteria cannot be demonstrated to the satisfaction of the Minister, the proposed component will not be included in the OSR project.

2.2.3.3 Projects as Economic Units

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(d)

The Minister must consider whether or not each part of the Project is economically justified. The project design, development plans, facilities and boundaries must all be justifiable for business and economic reasons. In addition, each component of the project must be economically justifiable and operationally integrated. Project components may include all operations, equipment and facilities associated with the recovery and processing of oil sands, and with the transportation of oil sands products to the project's boundary.

A Note on Terminology

> The definition of an economic unit for the purposes of oil sands royalty may differ from the developer's definition of an economic unit.
>
> The economic unit that constitutes an oil sands royalty project includes ***only*** those components that the Department considers directly related to oil sands recovery, processing and transportation within the approved project area.
>
> From the developer's perspective, these components may be part of a larger project that includes facilities or operations outside the OSR-approved project area. An example would be an upgrader. A developer may choose to have the upgrader excluded from the OSR-approved project, even though it is part of the developer's oil sands project.

2.2.3.3.1 Economic Justification for Project Expansions

One of the goals of the generic oil sands royalty regime is to facilitate staged development. This means that, over time, a project may expand and grow. As long as the project's growth is reflective of existing operations, albeit carried out on a larger scale or larger production base, the Department may approve an amendment to the original project approval order. (see 2.1.1.2, "Project Amendments")

The Department *will likely not* approve a project amendment once the project has reached a size when further growth would not create economies of scale. In this case, the developer would need to apply for approval for a new, stand-alone project.

2.2.3.3.2 Economic Justification for Project Amalgamations

The Department *may* approve the amalgamation of oil sands royalty projects if this is economically justifiable. In making this determination, the following principles will be considered:

- Whether or not a project is capable of sustained production.
- Whether or not a project has a cost balance that is unlikely to ever be recovered.

Amalgamated *projects* must adhere to the same criteria as all other projects: they must have Board approval(s), and satisfy the common management and the 50-kilometre limit considerations. Furthermore, the amalgamated project must be justified for economic reasons. If any other aspect of the proposed definition for the amalgamated project does not materially benefit the project's profitability, the Department will likely not approve the **amalgamation**. The Department will also consider the Crown's royalty share from the amalgamated project. The practice of the Department has been that if any portion of the amalgamation results in the Crown's royalty share shifting away from the Crown and moving to the project owners, the Department will not approve the amalgamation until it is revised to protect the interests of the Crown.

2.2.3.4 Protecting the Crown's Royalty Share

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(3)(f)

The project must be viable and there must be a legitimate expectation of profit—including a reasonable return on investment. In addition, the project must not be structured in a way that reduces the amount of royalty payable to the Crown.

In reviewing oil sands royalty applications, the Department determines if any aspect of the project would shift royalty away from the Crown. It looks at how project descriptions may impact the present value of future cash flows to the project owners and the Crown.

An OSR project approval order will not be issued if any aspect of the proposed project

- does not contribute to the project's profitability (including royalty share), or
- shifts revenues to the project owner at the expense of the Crown

In such situations, the application will not be approved until revisions have been made to protect the interests of the Crown.

2.2.3.4.1 Crown Royalty and Project Expansions

Two criteria are used to evaluate the royalty impact of project expansions:

- present-value royalty impact
- time to reach payout

present-value royalty impact

The Department compares the present value of royalty that would be payable for the expanded project to the present value of royalty that would be payable if the proposed expansion and the existing project were treated as separate projects.

The long-term bond rate (see 4.2.1, "The Return Allowance") is used as the discount rate in determining the present value of the royalty cash flows. The analysis assumes

- that expenditure and production data are the same whether the project expansion is approved or not
- that the expected costs and production data for all future years of both the existing project and the proposed expansion have been included in the application to amend the project

time to reach payout

The Department compares the time it would take the expanded project to reach payout to the time it would take for payout to be reached if the proposed expansion and the existing project were treated as separate projects.

For example, if the current project was expected to reach payout in 7 to 8 years, an expansion that doubled the scale of the project would be expected to delay payout by roughly 4 years: a longer-term delay would be considered unreasonable. A smaller-scale expansion would be expected to delay payout for less than 4 years. A larger-scale expansion might delay payout for more than 4 years.

2.3 The Components of an Oil Sands Royalty Project

The information components of an oil sands royalty project include

- the project name
- the project approval order number
- the project owner(s) and ownership considerations
- the project operator
- the lands and leases that have been approved as part of the project
- the project operations, including the recovery method and technology that have been approved, the product that will be produced and the approved production capacity
- project facilities (including the required EUB approval orders) and infrastructure
- the effective date of the project
- the project's prior cumulative net balance

These information components are specified in applications for approval of an OSR project and in the appendices and attachments accompanying the Ministerial Order issued when an OSR project is approved.

2.3.1 The Project Name

The project name, in conjunction with a Department-assigned project approval order number, serves to identify the project in Department of Energy information systems and records.

The name assigned to a project should serve as a specific identifier (for example, Elk Point Project or Project ABC). The name should remain applicable for the duration of the project, regardless if owners, operators or project specifics change.

Since ownership arrangements may change over time, the names of project owners should not be included as part of a project name.

2.3.2 The Project Approval Order Number

A provisional project approval order number is assigned when an oil sands royalty project application is received by the Department. Project approval order numbers begin with the prefix OSR (for Oil Sands Royalty). They are assigned sequentially: OSR 001, OSR 002 and so on.

If the OSR project application is approved, the project approval order number forms part of the project approval document. Together with the project name, it identifies the project in the Department's information systems and records.

The OSR project approval order number generally applies throughout the life of a project. If a project is amended, a letter is added to the number. For example, if Project OSR 001 is amended, its project approval order number normally becomes OSR 001A. If it is amended again, its project approval order number normally becomes OSR 001B, then OSR 001C and so on.

The OSR project approval order number should be cited in all correspondence with the Department.

2.3.3 The Project Owner

The project owner is an individual or corporation that has leased the right to develop and use oil sands resources from a defined land area or subsurface stratum. The extent and duration of the owner's rights are specified in an oil sands agreement called a lease. The project owner is often called the lessee.

An oil sands royalty project may have single or joint ownership. When there is more than one owner, each owner's equity share and obligations for royalty payment are specified in an operating agreement.

Operating agreements must be filed with the Department as part of the application for OSR project approval. The Department must be notified in writing if there is a change in project ownership.

Project Owner: A Legal Definition

> As defined in *section (1)(cc)* of the Regulation, a project owner is the **lessee of oil sands rights,** or, in the case of freehold mineral rights, the person who, according to Land Titles Office records, **has the right to recover oil sands** from the development area of a project.

2.3.4 Ownership Considerations

2.3.4.1 Freehold Interests

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 16(1)(b)

When freehold mineral rights are included as part of a proposed oil sands royalty project, a unit agreement is required before the project can be approved. The unit agreement is made between the owner of the freehold mineral rights and the Crown. It specifies the terms that govern the sharing of production costs and revenues.

Unit agreements must be filed with the Department as part of the application for OSR project approval.

2.3.4.2 Qualifying Joint Ventures

Oil Sands Royalty Regulation*, 1997 (AR 185/97), section 19*

Some types of jointly owned oil sands royalty projects are considered qualifying joint ventures under the Regulation. The cost rules for qualifying joint ventures are slightly different from those for other jointly owned OSR projects, which are referred to as non-qualifying joint venture projects. In calculating royalty, the cost of basic research is an allowed cost for qualifying joint ventures, but not for non-qualifying joint venture projects. For qualifying joint ventures, fees related to the management of the joint venture are not allowed. Fees related to the marketing of oil sands products are also not allowed unless they are incurred by the project operator.

In order to be classified as a qualifying joint venture, an oil sands royalty project must meet all the following criteria:

ownership structure

- The joint venture must have two or more project owners.
- The owners must be independent entities.
- No owner or group of owners may hold a majority interest in the project.
- The ownership structure must be the same for all aspects of the project, including all project-related agreements, freehold lands and facilities.

purpose

- The sole purpose of the joint venture must be the production of oil sands products from the operations and facilities included in the project description.

project operator

- The operation and management of the project must be the sole business activity of the designated project operator.
- The project operator must have no income and no deductions for the purposes of the *Income Tax Act* (Canada).

The operating agreements for qualifying joint venture projects must be filed with the Department as part of the application for OSR project approval.

2.3.5 The Project Operator

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 1(r) and 16(2)(a)(v)

The project operator is the person or corporation responsible for the management and operation of an oil sands royalty project. Project operators have the legal authority to represent the project and its owners.

Project operators are responsible for

- filing project reports, including operator's forecasts, monthly reports and end of period statements

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 27, 28 and 29

- maintaining records suitable for audit (project owners have this responsibility as well)

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 30

- paying royalty

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 31

- paying penalties or interest charges levied under the terms of the Regulation

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 32

- keeping the Department informed about changes to contact information, project ownership or other project-related details

The project operators may apply for oil sands royalty project approval as the designee of the project owners. In some cases, the project operator is also the owner of the oil sands project. If the operator is not the owner, or is one of several owners, the project operating agreement must be included as part of an application for OSR project approval. The operating agreement verifies that the designated operator is authorized to represent the project.

If the project operator should change, the Department must be notified in writing. The Department will not accept royalty payments from or release project-related information to anyone but the authorized project operator.

2.3.6 Lands, Leases and Mineral Rights

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 17(1)(b)

An oil sands royalty project comprises the surface area and subsurface oil sands strata that will be used to produce or process bitumen. Collectively, the lands and subsurface strata that are included in the project description are called the project development area.

2.3.6.1 Project Leases

The mineral rights included in a project are identified by an oil sands lease number.

Subsurface strata are identified by EUB zone designations or deeper rights reversion zone designations :

- for example, the Wabiskaw-McMurray deposit as described in Zone Designation 3412

2.3.6.2 Project Lands

The surface areas included in a project are identified by the Dominion Land Survey System description that indicates the relevant section, township, range and meridian:

- for example, Section 12, Township 64, Range 6, West of the 4th Meridian (This can also be written as 12-064-06 W4M.)

Except for upgraders, no part of an oil sands royalty project can normally be more than 50 km away from any other part.

2.3.7 Project Operations

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17

Project operations include all the activities required to recover, process and transport the approved project output (i.e., oil sands products) to the project boundary. If the project includes an upgrader located outside the boundary, project operations may include transporting the output to the upgrader.

2.3.7.1 Recovery Methods and Other Technology

Depending on the nature of the project, project operations may include activities such as

- primary recovery
- secondary recovery (e.g., waterflood, emulsion flood)
- thermal recovery
- solvent recovery
- mining
- on-site processing (cleaning)
- provision of thermal energy, with or without electricity generation
- storage until the product is transported to market
- upgrading

The recovery methods and technology approved for an oil sands royalty project are specified in the OSR project approval order.

2.3.7.2 Oil Sands Products

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 1(q)

An oil sands royalty project may produce one or more of the following products:

- dirty crude bitumen (see 4.6.1, 'Project Output')
- cleaned crude bitumen
- synthetic crude oil
- sulphur, metals, or other products (except natural gas) obtained by processing or reprocessing oil sands

The approved production capacity for each approved product may be specified in the OSR project approval order.

2.3.8 Facilities and Capital Assets

The facilities and capital used by a project are specified and approved in the oil sands project approval order.

Facilities

Examples of project **facilities** include:

- disposal facilities
- steam generation plants
- cleaning or treatment plants
- cogeneration plants
- upgraders
- other facilities related to oil sands production

Capital Assets

Examples of **capital assets** include:

- wells and batteries
- injection wells (including steam, solvent and other types of injection facilities)
- observation or delineation wells
- source water wells
- water monitoring wells
- disposal wells
- infrastructure such as roads, buildings, bridges, electricity transmission lines or other project assets
- pipelines used to connect project components or transport outputs to the project boundary. (Sales pipelines are not eligible as components of oil sands royalty projects.)

If the Department has approved a particular asset or facility as part of an OSR project description, eligible costs that are attributable to the approved asset or facility are considered allowed costs that can be deducted for royalty calculation purposes. The revenues attributable to the approved asset or facility must also be claimed as "other net proceeds."

The Department will not approve facilities or capital assets that do not meet the requirements for OSR projects. Approved project facilities and assets are specified in the OSR project approval order. Facilities and assets cannot be added or removed from the project unless permitted under the OSR project approval order, or unless an application to amend the OSR approval order is approved by the Department. (see 2.1.1.2, "Project Amendments")

2.3.8.1 Shared Facilities

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 17(2)

When processing facilities are co-owned with another project, processing costs are allocated in proportion to each project's ownership. For example, a project owner who owns a 50% share of the processing facility can claim 50% of the facility costs as allowed costs.

If the processing is not in the same proportion as the ownership, a cost equalization payment is made to account for the difference. The cost equalization payment is considered to be custom processing, which is treated as other net proceeds (see Figure 4, in 4.6.3).

The capital and operating costs of a shared facility such as the operating control room for cogeneration plants or for stand-alone steam and electricity power plants is allocated to steam and electricity in direct proportion to the capital cost of the facilities incurred for their respective "unshared" or single purpose facilities.

2.3.9 The Effective Date

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 16(2)(a)(ii), 16(2)(b)(ii) and 16(3)

The effective date of an oil sands royalty project is the date from which royalty begins to be calculated under the terms of the *Oil Sands Royalty Regulation, 1997* AR (185/97).

A provisional effective date is assigned when the Department receives an OSR project application. The provisional date is confirmed or revised (if necessary) during the project approval process. The project's official effective date is identified in the project approval document.

The Department cannot assign a provisional effective date until a complete project application—including the required EUB approvals, complete costs and revenue data and project economic forecasts—has been provided.

The effective date is the later of the following two dates:

- first day of the month in which the application was received
- the first day of the month *following* the month in which EUB approval was granted

For example, suppose the Department receives an OSR project application on April 23. EUB approval is granted on June 16. The project's effective date is July 1—that is, the later of April 1 (first day of the month in which the application was received) and July 1 (the first day of the month *following* the month in which EUB approval was granted).

Section 16(3)(c) of the 1997 Oil Sands Royalty Regulation states that the provisional effective date cannot be earlier than the first day of the month that precedes by 9 months the month in which the Ministerial Order approving the project or project amendment is signed.

2.3.9.1 Deferrals

Oil sands royalty project applicants may wish to defer the effective dates of their projects. In this case, the Department may assign an effective date that is later than what would normally be assigned under the terms of the Regulation.

Requests for a deferred effective date must be included with the project application.

2.3.9.2 EUB Approvals and Effective Dates

Schemes, operations, and facilities that are approved by the EUB after a project's effective date are not considered part of the project. Their associated costs and revenues cannot be used as part of the royalty calculation unless a project amendment is approved.

2.3.10 Prior Net Cumulative Balance

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 18

The prior net cumulative balance (PNCB) of an oil sands royalty project is the **opening balance** of cumulative costs less cumulative revenues incurred within a limited time period prior to the project's effective date. The opening balance is sometimes also referred to as the **unrecovered balance**.

The definition of project payout recognizes that balances are fluid. Once an oil sands royalty project has been approved, the unrecovered balance carries over from year-to-year. Payout is the first date at which, for a pre-payout project, there is no unrecovered balance.

The prior net cumulative balance is the unrecovered balance at the point when an oil sands royalty project is approved. It is an important component of the payout calculation that determines the project's royalty rate.

A project expansion will have its own prior net cumulative balance initially. Upon the expansion being approved by the Minister, this opening balance will be rolled into the remaining unrecovered balance of the larger project.

Oil sands developers submit their calculations of prior net cumulative balance as part of their application for oil sands royalty project approval. Costs and revenues are disclosed on standard Department of Energy forms and reviewed by the Department as part of the application process. Through the course of the review, the Department removes or adjusts ineligible costs or costs that cannot be supported by the necessary paper trail. Applicants should submit summaries of authorizations for expenditures (AFE) or other corporate budgetary documents to substantiate their prior net cumulative balances. The resulting, Department-approved prior net cumulative balance is identified in the project approval document. Prior net cumulative balance, as with any cost or revenue item, is subject to verification through a Crown audit.

Notes

- Once a prior net cumulative balance (PNCB) has been defined as part of an OSR project approval, the period is fixed. The approved PNCB period cannot be changed by the project owner or operator.
- If an OSR project with an unrecovered balance is sold, the outstanding unrecovered balance remains fixed, regardless of whether the sales price was more or less than this amount.

2.3.10.1 Eligible Costs

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 18(1)(a)(i)

Capital and operating costs that are directly attributable to recovering, processing, and transporting oil sands products within the project's boundary may be included in calculating the project's prior net cumulative balance. The cost rules are the same, whether the cost was incurred before or after the project's effective date.
(see 4.2.2, "Allowed Costs")

2.3.10.1.1 Pre-project Royalty

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 18(1)(a)(ii)

Royalty paid to the Crown under the *Oil Sands Royalty Regulation*, *1984* (AR 166/84) or under a Crown agreement is included as a cost in opening balance calculations for oil sands royalty projects.

2.3.10.2 Excluded Costs

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 18(1)(b)

The Minister must take into consideration whether the following costs should be excluded or deducted from calculations of an oil sands royalty project's prior net cumulative balance:

- costs incurred during periods in which oil sands development was suspended or abandoned
- costs incurred to recover oil sands products to which the *Experimental Oil Sands Royalty Regulation* applied
- costs that would not qualify as allowed costs if they were incurred after the project's effective date
- any costs in respect of which allocable costs have been established

- the Crown's share of revenue received for project substances (corresponding to the costs incurred to recover those substances), and other revenue that would be considered other net proceeds had it been received after the effective date

2.3.10.3 Timing

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 18(1)(a)(i)(A to C)

In most cases, the opening balance calculation of an oil sands royalty project is limited to costs incurred up to three years before the project's effective date.

The Department *may* allow costs incurred within a given period up to five years before the effective date if the applicant can demonstrate "diligent and substantial action" was taken within that period to obtain the EUB approvals needed to develop or expand the project.

Costs incurred more than five years before a project's effective date are usually not eligible for opening balance calculations. The Department *may* make an exception if the project owner can demonstrate that significant cost savings will result if the assets are used for the oil sands royalty project.

Note

An OSR project applicant must specify the time frame within which the project's opening balance was accumulated. Once this time frame has been specified, it cannot be changed.

3. Applying for Generic Royalty Terms

3.1 When Is an Application Required?

The generic oil sands royalty regime does not apply automatically – by default royalty is payable under the *Oil Sands Royalty Regulation*, *1984* (AR 166/84), as amended. Oil sands developers must apply for approval for new oil sands royalty projects and for all significant amendments to currently approved OSR projects. The application process is the same for each type of project.

3.2 Who Can Apply?

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 15(1) to 15(4)

Applications for oil sands royalty project approval (for a new project) or for an approval amendment (for a current OSR project) can be made by

- the project owner
- the project owner's designee
  - Project owners may authorize another individual or corporation to make the application on their behalf. In most cases, the owners' designee is the project operator.

If the application is made by the project owner's designee, documentation authorizing the designee to apply must be submitted together with the application. A letter from each project owner clearly authorizing or consenting to the application being made by the designee is sufficient.

If the application includes freehold rights, documentation confirming that the lessee of these rights has authorized the application must be submitted.

If the application deals with a project expansion, documentation confirming that the lessee of the lands and subsurface strata being added by the proposed expansion has consented to the application must be submitted.

3.3 The Application Process

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 16(1)

3.3.1 Consulting with the Department

Oil sands developers are encouraged to consult with the Department about their applications for oil sands project approvals and amendments. The Department can provide guidance and advice about the suitability of a proposed project or amendment and about factors that should be addressed in preparing the application.

Questions about specific applications or about the application process may be directed to Colin Pate at 780.427.6513.

3.3.2 Making an Application

Applications for oil sands royalty project approval must follow the format specified by the Department.

Applicants must use the standard Department of Energy application form, which can be downloaded from the Department website.

A sample "Application for Royalty Terms of the Oil Sands Royalty Regulation, 1997 (AR 185/97)" is included in the Appendix.

3.3.2.1 Required Information

Information must be provided for all sections of the project application form. There is no limit on the amount of information that can be included for each section.

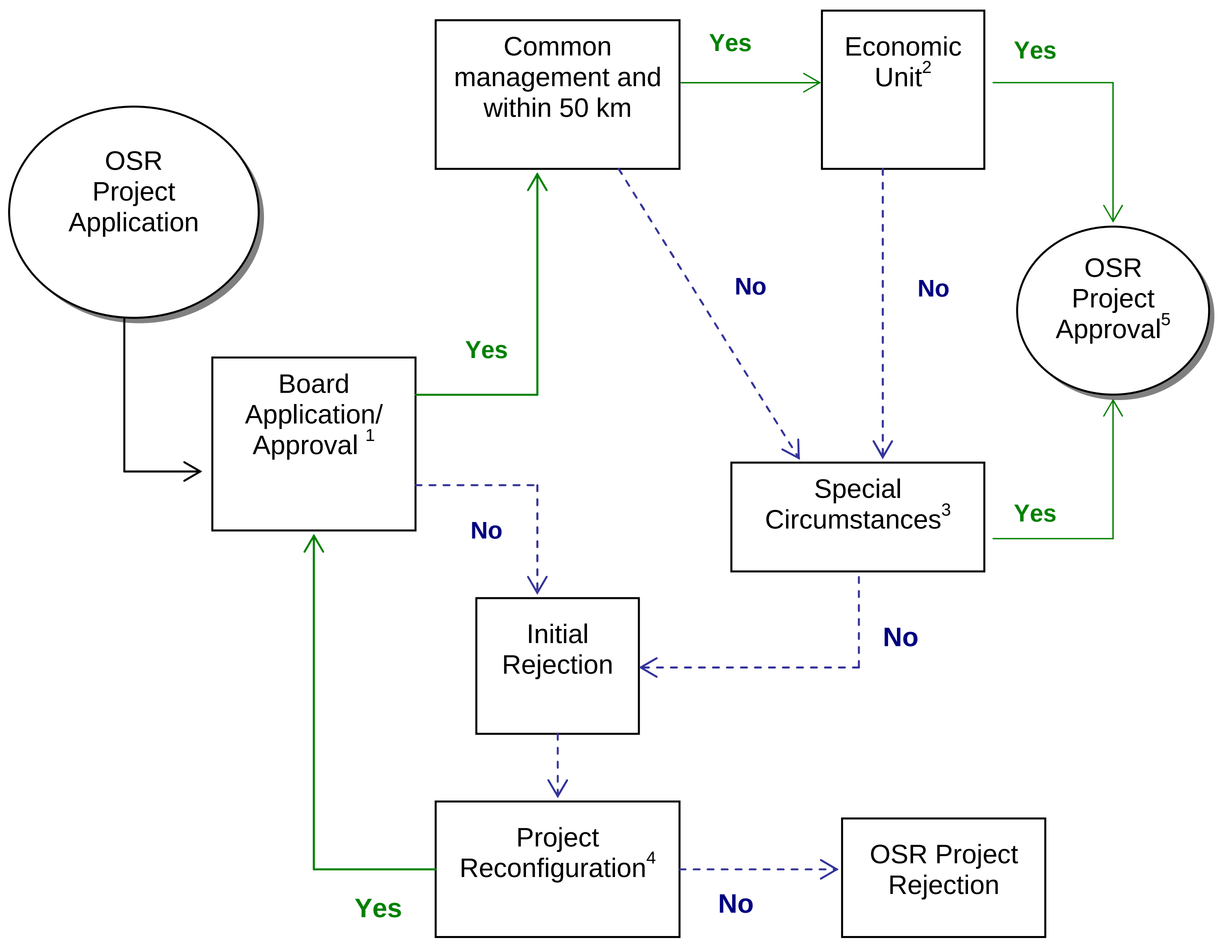
Incomplete applications are returned to the applicant so that missing information can be added. (Supplementary information that is provided by mail, email or in discussions with Department staff will not be considered as part of the application.)

3.3.2.2 Submitting a Completed Application

Applications for OSR project approval must be submitted in hard copy format to the attention of the Director of Operational Policy, Oil Sands Development.
(See Appendix J, "Contact Information")

As a courtesy to developers, the Department may accept an application by email or fax, as long as a hard copy is subsequently submitted within a reasonable time established by the Department.

Figure 1: The approval process for oil sands royalty projects



Notes:

[1]All project components require Board approval, and must include a scheme or operation approved under the Oil Sands Conservation Act, in order to receive OSR project approval. The applicant may apply for the OSR and Board approvals concurrently.

[2]Proposed project boundaries and facilities must be justified for economic reasons. If any aspect of the proposed project definition does not materially benefit the project's profitability, the Department will not approve that project definition. The Department will also consider the Crown's royalty share. If the Department determines that any aspect of the proposed project definition results in a shift of the Crown's share of project revenue to the project owner(s) and away from the Crown, the Department will not approve that application until it is amended to protect the Crown's interest.

[3]The Department will consider special or unforeseen circumstances that may justify project approval. Such circumstances will be reviewed on a case-by-case basis, where every case is considered on its own merits. These Guidelines provide direction, but are not intended to replace the requirement for case-by-case consideration.

[4]If a request for project approval is rejected at any level, the applicant must restructure the proposal in order for the project to be reconsidered.

[5]Project approval may contain conditions such as dealing with measurement of costs/revenues, non-arm's length fees, etc.

3.3.3 Completing the Application Form

3.3.3.1 Project Status

The applicant must indicate the type of OSR project for which application is being made. OSR projects may be

- new projects
- amendments to approved oil sands royalty projects, including
  - expansions
  - amalgamations
  - other significant changes to the project description

For details, see 2.1.1, "Types of OSR Projects".

3.3.3.2 Project Ownership

Project applications must identify and provide contact information for all project owners.

When there is more than one owner, the application must identify each owner's equity percentage. A copy of the operating agreement must be included.

When the project includes freehold rights, a copy of the unit agreement must be included.

Applicants who feel their projects are qualifying joint ventures, as defined by the Regulation, must include a copy of the joint venture agreement.

For details about project owners, see 2.3.3, "The Project Owner". For details about freehold interests and qualifying joint ventures, see 2.3.4, "Ownership Considerations".

3.3.3.3 Project Identification

In this section, applicants identify the project name (see 2.3.1, "The Project Name"), the project operator (see 2.3.5, "The Project Operator") and the contact person. If the application is for a project amendment, the OSR project approval number should be included as well.

The project **contact person** is the individual to whom the Department will direct all correspondence and inquiries regarding the project.

The project application should provide the following details about the designated contact person:

- *name*
- *title*
- *company*

- *mailing address*
- *courier address (as appropriate)*
- *telephone number and area code*
- *fax number and area code*
- *e-mail address*

The project operator is responsible for notifying the Department whenever contact-related details change.

3.3.3.4 Project Overview

Applicants must provide a summary of the project's history and development plans. The summary should include the following information:

- *the dates when lands and leases were acquired*
- *the locations of the first wells on the project site and the dates they were drilled*
- *a description of the lands and facilities included within the proposed project*
- *a history of project / operations development work completed to point of application*
- *a description of costs incurred to date*
- *an outline of the expected project production, operations, and future development plans and investment*
- *annual production to date*
- *other relevant details*

Applications pertaining to project amendments must describe the relationship between the proposed amendment and the existing project. Applications that do not provide this information will not be processed.

3.3.3.5 Project Description

The Department reviews oil sands royalty project applications on the basis of information provided in this section.

Errors in the project description may result in errors such as lands and facilities being excluded from the project description issued as part of the OSR approval order. Costs may be disallowed as a result.

The project description should include details about the relevant

- *EUB approvals*
- *lands, leases and mineral rights*

- *project operations*
- *facilities and other capital assets*

A **map or air photo** showing the project development area and facilities must also be included.

Applicants who wish to defer the effective date of their project must include a request for deferral as part of their application.

3.3.3.5.1 Alberta Energy and Utilities Board Approvals

The production schemes, operations, processing plants, wells and facilities of a proposed oil sands royalty project must all be approved by the Alberta Energy and Utilities Board (EUB). (see 2.2.1, "EUB Approval".)

Copies of all relevant EUB approvals must be filed with the Department as part of the application for OSR project approval. A description of each EUB-approved project component, with approval attached, should also be included.

If the approvals include specific terms or conditions required by the EUB, this should be brought to the Department's attention.

The required EUB approvals must be in place before an oil sands royalty project can be approved. (see Figure 1: The approval process for oil sands royalty projects)

3.3.3.5.2 Applying Before EUB Approvals Are Granted

Some applicants may find it expedient to apply for generic royalty treatment at the same time their oil sands development application is submitted to the EUB.

Although the Department cannot approve an OSR project application until EUB approvals are in hand, it *can* provide the applicant with a preliminary review and assessment and identify issues that need to be addressed. Resolving these issues before EUB approvals are granted may save time.

All the necessary EUB approvals must be received at the Department **within 90 calendar days** of the original OSR project application date.

If the required EUB approvals are received within 90 days, they must be forwarded to the Department together with a revised prior net cumulative balance. The revised statement must reflect project activities in the time between the date the application was first submitted to the Department and the date EUB approval was granted. The latter date determines the effective date of the OSR project.

If the Department does not receive the required EUB approvals within 90 days, the application expires. The Department sends a letter to advise the applicant that a new application must be submitted if OSR project approval is still required.

3.3.3.5.3 Lands, Leases and Mineral Rights

Applicants should provide the following information about the project development area:

Project Lands

- legal land descriptions (section, township, range and meridian) that define the **surface areas** included in the project

Project Leases

- the **lease number** and **lease description** for all leased land included within the project
- the **subsurface strata** (geological names and zone designations/deeper rights reversion zone designations) and **deposits** from which oil sands products will be recovered

> Deposits covered in an oil sands lease cannot be approved as part of an OSR project unless the development of the deposits has been approved by the EUB.

3.3.3.5.4 Project Operations

Applicants should describe

- the recovery methods and technology that will be used
- the oil sands products that will be recovered or processed

Process flow diagrams must be included with the description of project operations. These diagrams should indicate the design capacity of all major components.

3.3.3.5.5 Facilities and Other Capital Assets

Applicants must provide the following information about each facility and asset required to produce the proposed oil sands products

- the function
- the location
- the facility name and identification code, if available
- the appropriate EUB approvals or permits

All shared (co-owned) facilities and all off-lease facilities and assets must be clearly identified. Each owner's equity share must also be specified.

3.3.3.5.6 Wells

Applicants must provide the name, unique well identifier and finished drilling date for all wells included in the proposed project.

Note

> If an asset or facility is not clearly identified by the project applicant, it will not be included in the project description that forms a part of an OSR project approval order. Unless the asset or facility is included in the project

description, its costs are not allowed as project costs and cannot be considered in calculating the prior net cumulative balance.

3.3.3.5.7 Financial Details

Financial information submitted by an oil sands royalty project applicant is treated as confidential in accordance with section 50 of the Act and with the *Freedom of Information and Protection of Privacy Act*, RSA 1994, c. F-18.5.

All financial information is subject to verification by Department of Energy auditors.

Project costs and revenues must be itemized on standard **prior net cumulative balance (PNCB)** forms and **supported by authorizations of expenditure (AFE)** or comparable budgetary approval documents and invoice numbers. Relevant AFE should be submitted as part of the OSR project application.

Applicants may download the required PNCB forms from the Department website or use in-house equivalents. For samples of the Department's standard PNCB forms, please refer to the appendices.

The following PNCB forms must be submitted for each scheme or operation proposed for inclusion in the oil sands royalty project. Separate forms must be completed for each scheme:

- Calculation of Prior Net Cumulative Balance: Summary
  - This form summarizes the costs and revenues for the appropriate period. Applicants must provide information for all the categories included on this form.
- Prior Net Cumulative Balance: Cost Detail
  - A cost detail form must be completed for each year reported on the summary form.
  - For all capital assets listed on this form, the corresponding AFE number should be cross-referenced on a separate sheet.
  - NOTE: The categories included on this form are intended as examples. Project applicants may substitute the listed categories with ones that reflect their particular operations.
- Prior Net Cumulative Balance: Revenue Detail
  - A revenue detail form must be completed for each year reported on the summary form. Applicants must provide information for all the categories included on this form.

The project operator should include an electronic transaction listing of capital and operating expenses claimed that reconciles with the total amounts claimed on the

PNCB. This file should include enough information to allow the Department of Energy auditors to trace a transaction to its supporting documentation.

For details about prior net cumulative balance calculations and timing rules for eligible costs, see 2.3.10, "Prior Net Cumulative Balance".

3.3.3.5.8 Forecast Data

> All applications for proposed projects or proposed project amendments must be accompanied by economic forecast data. Any applications not including these data will be considered incomplete applications.
>
> Financial information submitted by an oil sands royalty project applicant is treated as confidential in accordance with section 50 of the Act and with the *Freedom of Information and Protection of Privacy Act*, RSA 1994, c. F-18.5.

The Regulation requires the Minister to consider the economics of all proposed projects and proposed amendments to projects. Where, for example, a project expansion is proposed, the operator must submit data for two cases: a standalone case, where the project and the proposed expansion are treated as independent, separate projects, ignoring any synergies or economies of scale; and a combined case, where the project and proposed expansion are joined. A minimum of 10 years of annual data must be provided, and in some cases the Department may request more data. To facilitate the economic evaluation of proposed projects and proposed project amendments the applicant must submit the following information for both cases:

- Sales volumes for each oil sands product (i.e., crude bitumen, blend, Synthetic Crude Oil (SCO) etc.) in cubic metres per year, indicating API, sulphur% and Total Acid Number (TAN).
- Sales price for each oil sands, product in $CDN per cubic metre.
- The quantities of arms length and non-arm's length dispositions for each oil sands product, in cubic metres per year.
- The quality differential for each oil sands product, and the benchmark used.
- Bitumen production volumes, in cubic metres per year.
- Handling charges for each oil sands product, in cubic metres per year, indicating blending fees, transportation charges, tankage charges and other handling fees.
- Other oil sands product revenues, by source.
- Natural gas volumes used, in cubic metres per year.
- Natural gas price, in $CDN per gigajoule.
- Diluent volumes used for each oil sands product, in cubic metres per year.
- Allowed operating costs, in $CDN, broken down by major cost categories.

- Allowed capital costs, in $CDN, broken down by major cost categories.
- Numbers of wells drilled to date and number of wells currently producing.
- Other net proceeds, in $CDN, broken down by source.
- Forecasted project payout date, for each case (i.e., separate project and expansion, combined project).

Applicants may download the required economic evaluation data forms from the Department website.

3.3.3.5.9 Signatures

Applications for oil sands projects must be signed by the **senior financial officer** who represents the project owner or the owner's designee and by the **individual who prepared the application**.

These signatures

- verify that the information included in the application is accurate
- authorize the Department to audit the information and to access additional project records, if required
- confirm that the applicant accepts responsibility for reporting project changes to the Department
- confirm the applicant's willingness to comply with the provisions of the Oil Sands Royalty Regulation, 1997 (AR 185/97)

3.4 The Approval Process

3.4.1 Department Review

When an oil sands royalty project application is received, Department staff review it to ensure that

- the application is complete
- all required attachments have been included
- the required signatures are present
- the proposed project meets the requirements of the Regulation (For details about OSR project requirements, see 2.2, "OSR Project Requirements")

If the application is in good order, a staff member assigns a provisional **project approval order number** (see 2.3.2, "The Project Approval Order Number") and a provisional **effective date** (see 2.3.9, "The Effective Date"). The application is then forwarded to the Department's Evaluations group, which reviews the economics and royalty impact of the proposed project (or proposed project amendment).

3.4.2 Project Approval: The Ministerial Order

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 16(2)

Once the financial information has been reviewed and accepted, a preliminary project approval order is drafted and forwarded to the Department's Legal Services branch. Branch staff prepares the final project approval order and assign a Ministerial Order number.

The Ministerial Order is signed by the authorized delegate of the Minister. The original document and related attachments are kept on file with the Department. Pertinent information is entered into the Department's royalty information system.

The Ministerial Order provides legal authority and approval for an oil sands royalty project. An **appendix** to the Ministerial Order

- *describes the project and indicates whether or not it is a qualifying joint venture*
- *specifies the effective date and the project approval order number*
- *specifies the prior net cumulative balance*
- *identifies the project operator*
- *outlines any **terms and conditions** to which the approval is made subject*

An example of a Ministerial Order and attachments is included in the Appendix B – "Project Application Forms and Approvals".

Confidentiality

> Ministerial Orders are not public documents. The information they contain is treated as confidential.

3.4.3 How Long It Takes

Department of Energy staff, makes every effort to expedite the exchange of information with project applicants. Assuming that a project application is complete—and if there are no unusual circumstances—the project approval process typically takes 6 months.

> Section 16(3)(c) of the 1997 *Oil Sands Royalty Regulation* states that the provisional effective date cannot be earlier than the first day of the month that precedes by **9 months** the month in which the Ministerial Order approving the project or project amendment is signed.

4. Calculating Oil Sands Royalty

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 16(2)

Under Alberta's generic oil sands royalty regime, royalty is based on the value of oil sands products sold in arm's-length transactions. When developers undertake approved activities related to their oil sands royalty projects, both the cost of these activities and the revenues they generate are included in the royalty calculation.

4.1 The Royalty Calculation Point

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 23

Royalty payable to the Crown is calculated on the volume of oil sands product that is delivered and measured at the applicable royalty calculation point.

For an oil sands royalty project, the royalty calculation point is the last point at which the Crown's royalty share of the project's oil sands products is measured.

If the oil sands product is **crude bitumen** that is not processed into other oil sands products, the royalty calculation point is the last point of measurement before the crude bitumen is permanently removed from project lands.

If the oil sands product is **cleaned crude bitumen**, the royalty calculation point is the last point of measurement before the bitumen leaves the cleaning plant. That is, *the royalty calculation point is the cleaning plant gate.* This royalty calculation point is used whether or not the cleaning plant is part of the project as long as, once the bitumen leaves the plant, it is disposed of, delivered to a non-project upgrader for further processing, or used for non-project-related purposes.

In the case of an **oil sands product other than crude bitumen or cleaned crude bitumen**, the royalty calculation point is the last point of measurement before the oil sands product leaves the processing plant. That is, *the royalty calculation point is the processing plant gate.* This royalty calculation point is used when the processing is part of the project, as long as, once the oil sands product leaves the processing plant, it is disposed of, delivered to a non-project processing plant for further processing, or used for non-project-related purposes.

4.2 Elements of the Royalty Calculation

The royalty calculation for an OSR project includes the following elements:

- the project's **opening balance**, which is the cumulative costs less cumulative revenues as of the project's effective date (see 2.3.10, "Prior Net Cumulative Balance")
- the return allowance (see 4.2.1, "The Return Allowance")

- allowed costs (see 4.2.2, "Allowed Costs" - including operating and capital costs and costs for goods and services)
- project revenues (see 4.2.3, "Project Revenues")
- the unit price (see 4.2.4, "Unit Price")

4.2.1 The Return Allowance

Mines and Minerals Act, sections 90(6) to 90(8)

When an oil sands royalty project reaches payout, its cumulative revenues equal or exceeds its cumulative costs. Upon payout, the oil sands developer has recovered his initial investment cost, including a return allowance. The return allowance is intended to offset the developer's return on investment.

The return allowance is calculated using Canada's **long-term bond rate**, which is the simple average of selected Government of Canada long-term benchmark yields. The monthly long-term bond rate is calculated as follows:

Monthly Rate = $(1 + \text{LTBR})^{1/12} - 1$

The Long-Term Bond Rate (LTBR)

Mines and Minerals Act, *sections 90(6) and 90(7)*

> The weekly LTBR is published by the Bank of Canada each Wednesday and can be accessed on the Bank of Canada website. The heading is identified as 'Government of Canada benchmark bond yields', then select Long-term-weekly.
> [URL: http://www.bankofcanada.ca/en/rates/bond-look.html]
>
> Project staff who prepares royalty reports may also access the appropriate LTBR from a table on the Department website (navigating through the royalty section of Oil Sands, and choosing Rates of Return).

4.2.1.1 The Return Allowance for Pre-Payout Projects

For pre-payout projects, the return allowance is an allowed cost. It is calculated monthly—by multiplying the net cumulative balance (the difference between the project's cumulative costs less cumulative revenues) by the long-term bond rate for the month. Together with other allowed costs and royalty paid for that month, it is added to the next month's cumulative cost to get the current cumulative cost for the project.

The return allowance for pre-payout projects is reported once a year, on the end of the period statements.

Project operators use the Pre-Payout Project, End of Period Statement Pre -4 form, to report the return allowance for the period. (Appendix E)

4.2.1.2 The Return Allowance for Post-Payout Projects

For post-payout projects, a return allowance is provided only when the project has a net loss at the end of a period.

1. **If the project begins and ends a period in a net loss position**, a return allowance is provided on the full period (365 days). The return allowance equals the average long-term bond rate for the period multiplied by the net loss for the period.

2. **If the project begins the period in a positive net revenue position but ends in a net loss position**, a return allowance is provided on half of the period's net loss. The return allowance is the product of average long-term bond rate for the period multiplied by (183/365) multiplied by the net loss for the period. If a project transitions from pre-payout status to post-payout status during a year and ends the remainder of the year in a net loss position, a return allowance is provided for the pre-payout period, and for 183/365ths of the post-payout period's net loss.

3. **If the project ends the period in a positive net revenue position**, no return allowance is allowed, regardless of the net revenue positions at the start of the period or in the intervening months. The return allowance for post-payout projects is reported annually on the end of period statements.

Project operators use the Post-Payout, End-of-Period Statement PST-6 form, to report the return allowance for the period. (Appendix G)

4.2.1.3 The Return Allowance for Suspended or Abandoned Projects

Oil Sands Royalty Regulation, *1997* (AR 185/97), schedules 1 and 2, section 5

The return allowance may be disallowed if the Minister has notified the operator of the project that the Minister is of the opinion that project operations have been or are substantially suspended or abandoned for a period of time.

The Minister may disallow the return allowance on a retroactive basis, if he is not informed of the "suspended" or "abandoned" operations until some time after they have occurred.

4.2.2 Allowed Costs

Oil Sands Royalty Regulation, *1997* (AR 185/97), schedules 1 and 2

For royalty calculation purposes, costs that are directly attributable to the recovery, processing and transportation of oil sands products to the boundary of an oil sands royalty project may be eligible for deduction as allowed costs.

For details about cost rules that pertain to specific types of goods and services, see 9.2.1, "Goods and Services"

4.2.2.1 Cost Rules

Oil Sands Royalty Regulation, *1997 (AR 185/97), schedules 1 and 2*

Allowed costs must satisfy all the following criteria. They must be

- directly attributable to the project
- reasonable in relation to the circumstances under which they were incurred
- incurred by or on behalf of the project owner
- incurred on or after the project's effective date (see 2.3.9, "The Effective Date")

Allowed costs must also meet at least one of the following criteria. They must be incurred

- to **recover oil sands** from the project's development area
- to **buy oil sands products** for processing or reprocessing at a processing plant that is part of the project
- to **process or reprocess** oil sands or oil sands products at a processing plant that is part of the project
  - In this case, allowed processing and reprocessing costs are incurred in association with products recovered from the project's development area *or* from purchased products.
- to **process** oil sands or oil sands products at a processing plant that is *not* part of the project, and before the oil sands products obtained are delivered at a royalty calculation point
  - In this case, the processing costs are allowed if the oil sands or oil sands product was recovered from the development area of a project or if the oil sands product was purchased and previously processed at a plant that is part of the project.
- to **transport** oil sands or oil sands products from one part of a project to another *or* from the project to a processing plant that is not part of the project
- to **market** oil sands products obtained from the project
- to **plan, design** or **engineer** project expansions
- to **conduct research** activities that are directly attributable to the project
  - Projects classified as qualifying joint ventures may also deduct the cost of basic research. (For details about allowable research costs see 5.6, "Research")
  - Basic research is not an allowed cost for projects that are not qualifying joint ventures.

- to provide **field, office, administrative** or other services in relation to the activities described above, with the following exceptions:
  - Unless a project is a qualifying joint venture, these services **are not** allowed costs if they pertain to marketing activities or to planning, designing or engineering project expansions.
  - Only qualifying joint ventures may deduct all administrative costs.

Specific Cost Rules

Specific rules apply to the following types of allowed costs:

- solution gas gathering and fuel gas distribution
- pipelines that are not considered basic services
- co-generation plants
- custom processing
- research

Details about these types of costs are provided in Chapter 5, "Specific Cost Allocation Rules"

4.2.2.1.1 Approval

The Minister will determine whether any costs claimed by an operator are allowed costs of a project. All costs claimed are subject to verification and audit.

4.2.2.1.2 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), section 7(2)*

All project-related costs—including allowed capital, operating, and research and development costs—are 100% deductible in the year in which they are incurred.

An allowed cost is deemed to be incurred

- in the month in which the cost is payable
  - if the month occurs during a **pre-payout period** and the cost is paid not more than 12 months after the end of that month
  - or
  - if the month occurs during a **post-payout period** and the cost is paid before the end of the calendar year following the period.

– *A post-payout project's year-end is always December 31. If the project owner receives an invoice in July of Year 1, the invoice must be paid no later than December 31 of Year 2 for the cost to be claimed as an expenditure in July of Year 1.*

or

- in the month in which the cost is paid, in any other case

For a **non-arm's-length transaction** for the supply of services or materials to the project by a project owner, operator, or an affiliate of either of them, and for which no invoice has been issued, an allowed cost is deemed to have been incurred in the month in which services were supplied or materials were received. (see 9, "General Non-Arm's Length Rules")

4.2.2.2 Types of Allowed Costs

The following types of costs <u>may</u> be allowed if they meet the requirements of the Regulation. The list is not comprehensive and is only intended to provide guidance.

All deductible costs are subject to financial audit by the Department. Research costs are subject to a concept audit before the costs are incurred.

ALLOWED CONSTRUCTION AND CAPITAL INVESTMENT COSTS
▪ the cost of acquiring, constructing or replacing property, plant and equipment, including – the cost of equipment, materials and supplies before installation or assembly – the direct and allocated cost of constructing, installing, assembling or erecting plant and equipment, including the cost of labour, benefits and an appropriate allocation of plant overhead costs *Note: Plant overhead costs allocated to property, plant and equipment <u>must not</u> include non-construction–related costs. Those portions of the overhead are not allowed costs.* – the cost of work performed by other companies or individuals
▪ the cost of purchasing land and buildings
▪ the cost of drilling, completing, recompleting, testing, capping, plugging and abandoning, deepening, plugging back or redrilling a well, or converting a well to a source, input, observation or producing well
▪ the cost of planning the de-bottlenecking or further phases or expansions of the oil sands project, including engineering, scheduling, and contract preparation and review.

ALLOWED OPERATING COSTS
Deposits
▪ the cost of deposits payable to the Crown to ensure the proper reclamation of project lands
Labour, Services and Supplies
▪ the cost of salaries, wages, benefits, training, travel and relocation of operator's, lessee's or affiliate's employees whose work is directly attributable to the project
▪ the cost of employee severance, including associated relocation and training expenses
▪ the cost of employee safety equipment and safety, including the cost of preparing oil sands project safety manuals and implementing emergency procedures
▪ the cost of contract labour, material, supplies, chemicals, catalysts and services, including professional services
▪ the cost of supply management with regard to gas and diluent
▪ the personnel costs related to the purchasing of materials and supplies
▪ the cost of cost, production, and revenue accounting – These costs must be directly attributable to the project and supported by time allocation reports or other auditable documentation.
▪ the cost of internal (qualifying joint ventures only) and external legal services associated with damage claims and regulatory applications – These costs are not allowed if they result from a breach of any applicable law or relate to a royalty, interest or penalty dispute with the Crown. – Proceeds received or receivable as a result of a court judgment are considered "other net proceeds" of the project, unless they are received in respect of a claim against the Crown. – Legal costs associated with gas over bitumen issues are not allowed costs.
▪ the cost of marketing oil sands products, except overhead and the cost to provide field, office or administrative services in relation to marketing for non-qualifying joint ventures
▪ the cost of external audits
▪ the cost of penalties or compensation payable to a contractor when the operator is unable to complete the terms of an agreement – For example, an oil sands project operator who contracts to drill a specific number of wells but cannot complete the drilling program due to unforeseen circumstances may incur this type of cost.
▪ the cost of rent or lease payments related to equipment, plant and buildings
▪ the cost of insurance – Any proceeds received or receivable under an insurance policy are considered "other net proceeds" if the insurance premiums are allowed costs.

▪ the cost of computer systems – These costs must be directly attributable to the project and supported by auditable documentation.
▪ the cost of surface lease rentals and rentals under mineral agreements that grant the right to recover leased substances
▪ the cost associated with site drainage and overburden removal, including pre-stripping
▪ the cost of diluent – In determining gross revenue of a project, the cost of diluent is deducted from the project revenue.
▪ the cost of fuel
▪ the cost of licensed or purchased technology (including patents and other proprietary rights), if – the cost is payable to a person other than the lessee or an affiliate of the lessee or the operator – or – the cost is payable to the lessee or an affiliate of the lessee or the operator, and the Crown has approved the costs *Note: Any consideration received after the cost of the technology has been claimed is included as "other net proceeds."*
Repair and Maintenance
▪ the cost of repair and maintenance, including direct labour, benefits, materials and supplies, and work performed by other companies
Utilities
▪ the cost of telecommunications, power, water, sewage disposal and utility construction contribution payments

4.2.2.3 Costs That Are Not Allowed

The following costs may not be allowed costs in the royalty calculation since they may not meet the requirements of the Regulation.

COSTS THAT ARE NOT ALLOWED
▪ overhead or administrative costs, including costs related to internal audits and in-house legal services and other like expenses, for non-qualifying joint ventures where those costs are not allowed under section 2(e)(x) of Schedule 1 of the Regulation
▪ field offices or administrative services related to product marketing or project expansion planning, in the case of non-qualifying joint ventures
▪ in the case of qualifying joint ventures, management fees that are charged by a project owner or affiliate and are not costs of services and materials
▪ borrowing or financing costs
▪ charges for late payment or payment shortfalls
▪ an overriding royalty interest, carried interest, net profit interest, or any similar

COSTS THAT ARE NOT ALLOWED
interest—except as specified in schedule 3, section 101(n) of the *Metis Settlements Act.*
▪ escalating rent paid under the *Oil Sands Tenure Regulation*
▪ costs incurred to acquire an interest or estate in mineral rights, except when these costs relate to earning an interest through the development of the project or its infrastructure.
▪ costs related to the depletion or depreciation of assets ▪ costs relating to accounting losses incurred upon the sale of project assets
▪ costs related to the non-arm's-length transfer of research or technology
▪ costs incurred as a result of acts or omissions which breach the laws, rules or regulations of a government or government agency
▪ except for qualifying joint venture projects, costs incurred to conduct basic research
▪ fees or costs related to dispute resolution, involving a royalty, interest or penalty dispute with the Crown
▪ credits or discounts awarded to operators, project owners or affiliates to offset an eligible cost
▪ food, beverage or entertainment expenditures, to the extent that they would not be allowed under the Income Tax Act (Canada)
▪ any economic assistance (other than reductions in income tax payable) that is provided to the operator, project owner or affiliate by the Province of Alberta or the Government of Canada (or an agency of either) for the purpose of reducing or offsetting costs described in section 2 of each schedule of the Regulation
▪ costs which have already been used as allowed costs for another project
▪ costs that have been deducted in the calculation of unit price (see 4.2.4, "Unit Price")
▪ municipal fees and taxes
▪ goodwill (e.g., charitable donations, company events)
▪ consultation costs for organizations such as the Cumulative Effects Management Association (CEMA), the Lakeland Industry and Community Association (LICA) and the Athabasca Tribal Council (ATC). ▪ industry funding for the Regional Agreement (previously known as the Regional Long Term Benefits Agreement).

4.2.2.4 Claiming Allowed Costs

To claim allowed costs, project owners and operators must follow the guidelines outlined in this chapter. When project owners or operators are not sure if a particular cost is allowed under the Regulation, they may request an advance ruling from the Department. For details see Chapter 7, “Advance Rulings".

Project operators who are claiming research costs must submit the number of the approved budgetary approval form. For details about research costs, see 5.6, "Research"

4.2.3 Project Revenues

The revenues of an oil sands royalty project are determined by three factors:

- the **project description**, which identifies what resource recovery and processing facilities are included as part of the project
- the type of **oil sands products** that are sold
- the **unit price** calculation (see 4.2.4, "Unit Price"), which determines the revenue obtained from those oil sands projects

4.2.3.1 Types of Revenue

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 1(m), 1(p), 1(ee) and 22

Four types of revenue come into play in the royalty calculation:

- project revenue
- gross revenue
- net revenue
- other net proceeds

Project revenue is the sum of the volume of each oil sands product times the unit price for that product.

$$\text{Project Revenue} = \sum (\text{Product Volume} \times \text{Unit Price})$$

Gross revenue is the project revenue less the cost of diluent contained in any blended bitumen used in the revenue calculation.

$$\text{Gross Revenue} = \text{Project Revenue} - \text{Cost of Diluent}$$

Net revenue is the amount by which project revenue exceeds net project costs in a given reporting period. Net project costs are allowed costs less other net proceeds.

$$\text{Net Revenue} = \text{Project Revenue} - (\text{Allowed Costs} - \text{Other Net Proceeds})$$

When net revenue is calculated, the value of other net proceeds is deducted from the allowed costs (see 4.2.2, "Allowed Costs"). For projects that have reached payout, if other net proceeds exceed the allowed costs for the reporting period, the excess amount is carried forward to the next period.

Note: During pre-payout status, other net proceeds are included in the cumulative revenue amount.

Project revenue, gross revenue and net revenue are obtained from the sale or disposition of oil sands products. Revenue (proceeds) can also be earned as a result of selling, leasing or licensing project-related assets, technology or substances *other than* oil sands products. Revenue received or receivable from such activities is called **other net proceeds**. Other net proceeds cannot be collected unless the associated costs have been claimed as allowed project costs.

Additional examples of other net proceeds include

- proceeds from an insurance policy, provided the insurance premium was included as an allowed cost
- proceeds from a litigation settlement or threatened litigation, unless the litigation is against the Crown in respect of amounts paid or payable under section 90 of the Act
- pipeline- or transportation-related revenues
- custom-processing revenues
- revenues from the sale of steam, if a cogeneration plant is considered a part of the project

4.2.4 Unit Price

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 1(jj) and 21

The unit price is the net unit value of sold substances measured at the royalty calculation point. It is calculated as follows:

$$\text{Unit Price} = \frac{\text{Total Sales Proceeds} - \text{Handling Charges}}{\text{Total Sales Volume of the Oil Sands Product}}$$

Total Sales Proceeds include all money and services received or receivable for third-party dispositions in a specified month of a reporting period.

Handling Charges include all charges incurred in moving the oil sands product from the royalty calculation point to the point of disposition. The disposition point commonly either is the point of sale or the Alberta export terminal (Edmonton, Hardisty or Lloydminster) that is closest to the project. The cost of processing the product at any place between these two points is also considered a handling charge. Handling charges may also include export fees, pipeline tariffs, terminal and processing charges, and other fees.

Handling charges are not considered to be allowed costs, nor are they included in determining the prior net cumulative balance of a project or project expansion.

Total Sales Volume is a measure of the total dispositions of the oil sands product.

If the Minister is of the opinion that the quantity of an oil sands product disposed of in third party transactions is not sufficient to determine a unit price, the Minister will assign a fair market value to the product.

If dirty crude bitumen is disposed of, the unit price will be based on the fair market value of cleaned crude bitumen that could be obtained from that dirty crude bitumen. In determining the unit price, the handling charges will include charges that the Minister is of the opinion would have been incurred to transport the dirty crude to a place where it could have been processed, and the processing charges themselves.

Unit prices are product specific.

> A unit price must be calculated for each oil sands product produced by an OSR project.

4.2.4.1 Negative Unit Prices

If handling charges exceed total sales revenues, the unit price is negative. This means the sales revenue for the particular oil sands product is also negative. In this situation, no royalty payment for that product is made to the Crown.

How It Works

> Under Alberta's generic oil sands royalty regime, royalty is not production based. Rather, it is based on the value of oil sands products sold in arm's-length transactions.
>
> The Crown's royalty share is a percentage of the revenue from each oil sands product: this can only be a positive amount. Nonetheless, the proceeds from selling Crown royalty volumes can be negative if the unit price is negative. In this situation—that is, if handling costs exceed sales revenues—the Crown royalty value defaults to zero.

4.3 The Royalty Calculation for Pre-Payout Projects

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 31(1) and 31(3)

The Crown's royalty share for pre-payout projects is calculated and paid monthly at a rate of 1% of the project's gross revenue. The royalty proceeds from the disposition of the Crown's royalty share are calculated by multiplying the Crown's royalty share quantity by the unit price applicable to that quantity. If the product contains diluent, the Crown's share of the cost of diluent is deducted from the sales revenue of the blended product to determine the royalty payable to the Crown.

For pre-payout projects, negative oil sands product revenues cannot be deducted as allowed costs. Rather, negative revenues increase the payout balance (cumulative revenues less cumulative costs) and earn a return allowance.

In addition, since the Crown royalty share is calculated monthly for each oil sands product, the negative sales revenue for a particular product cannot be used to reduce positive sales revenues for other oil sands products reported in that month. (see Chapter 6, "Royalty Reporting and Payment")

Royalty and return allowance are allowed costs for pre-payout projects.

4.4 The Royalty Calculation for Post-Payout Projects

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 31(2), 31(3) and 31(4)

The Crown's royalty share for post-payout projects is based on an estimate of the total royalty payable for the period. It is paid as a monthly instalment, which is adjusted each month based on that month's estimate of the total royalty payable for the period. Estimates must be updated monthly because monthly expenditures and revenues (both actual and forecast) can affect the project's net revenue position.

The royalty payable for the period is the greater of 1% of gross revenue or 25% of net revenue: both amounts must be calculated to determine which is greater. In the latter case, the royalty percentage is calculated as follows:

Royalty Percentage = 25 * Net Revenue ÷ Gross Revenue

Note that the royalty percentage, above, is the Crown's royalty share of the oil sands product, expressed as a percentage of the oil sands product on which royalty is payable. To convert it to a dollar amount, the royalty percentage is multiplied by the sum of each oil sands product times its respective unit price – which is equivalent to 25% net revenue. (see Chapter 6, "Royalty Reporting and Payment")

For post-payout projects where the "1% of gross revenue" royalty rate is in effect, negative oil sands product revenues contribute to a net loss for the royalty-reporting period. The net loss becomes an allowed cost in the next reporting period.

4.5 Royalty Rules

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 24, 25 and 26

The royalty paid on oil sands products shall be free and clear of all deductions.

The Crown's royalty share must be included in all sales or dispositions of oil sands products. In selling or disposing of these products, the oil sands royalty project holder acts as an agent of the Crown. The terms of this agency are limited: although serving as the Crown's agent, the project holder does not acquire any of the rights, privileges, prerogatives or immunities of the Crown.

4.6 Project Configurations and Royalty

Project Sales and Revenues

For the project examples in this chapter, as for all oil sands royalty projects, project **sales** are sales of all oil sands products obtained from oil sands rights approved as part of the project description.

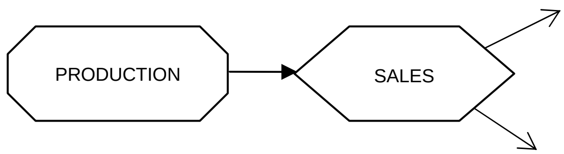
The revenue received from the sale of a product times the unit price (sales less handling charges) for that product is called the product revenue. The sum of product revenues is the **project revenue**.

Gross revenue is the project revenue less the cost of diluent.

Net revenue is the project revenue less allowed costs of the project less the other net proceeds earned.

4.6.1 An OSR Project that Produces Crude Bitumen

Figure 2: An oil sands royalty project with no processing facilities



Expanded example provided in Appendix K

Project Output

This type of project produces crude bitumen or bitumen that is cleaned at processing facilities that are not part of the project. Such facilities provide basic services for the project. (see 9.2.2, "Basic Services")

Cleaned crude bitumen is the first marketable oil sands product. Under the provisions of section 21(4) of the Regulation, if dirty crude bitumen is sold, the royalty calculation is based on the Department's determination of the revenue that could have been obtained had the bitumen been cleaned. In making this determination, the Department estimates the fair market value of cleaned crude bitumen. This amount—not the amount received for the sale of dirty bitumen—is used to calculate the unit price. The project's handling charges include the estimated cost of transporting the dirty bitumen from the place at which it was disposed of to a place at which could be cleaned and the estimated cost to process the dirty crude bitumen to produce clean crude bitumen.

Processing Costs: Allowed Costs versus Handling Charge Deductions

> Handling charges are those charges, including processing charges, incurred between the royalty calculation point and the point of disposition (see *section 22(2)* of the Regulation). On the other hand, allowed project costs for processing are those costs, in this example, incurred before the oil sands product is delivered to a royalty calculation point (see *Schedule 1, section 2(iv) and Schedule 2, section 2(iv)*. A charge cannot be deducted under both categories (see *sections 22(2) and 3(j)(iv))* of the schedules).

Allowed Costs

To the extent that it was not deducted as a unit price deduction (handling charge), the cost of cleaning crude bitumen may be deducted as an allowed cost. The allowed amount depends on whether or not the processing facility is at arm's length from the project. If an arm's length facility is used, the allowed cost is simply the cost of cleaning charged to the project. And if a non-arm's-length facility is used, allowed cost is the lesser of the amount charged or the cost of service. (see 9.2, "Cost Rules Associated with Non-Arm's-Length Transactions")

Royalty Calculation Point

This is the point at which crude bitumen is permanently removed from project lands, or if the crude bitumen is cleaned, the last point of measurement before it is delivered from the processing plant (that is not part of the project) from which it is obtained.

Project Royalty

Pre-payout royalty is 1% of the project's gross revenue—that is, 1% of the quantity of each oil sands product delivered at the royalty calculation point.

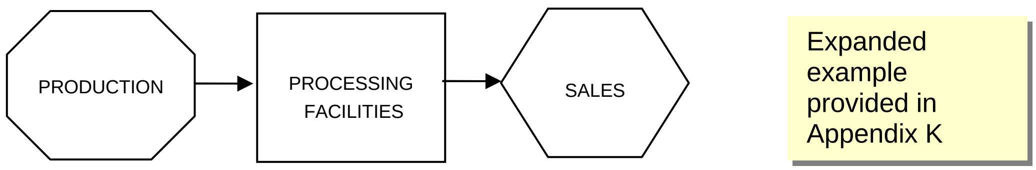
Post-payout royalty is the greater of 1% of the project's gross revenue or 25% of the net revenue for the period.

Net Cumulative Balance

This is the sales revenue *less* allowed costs attributable to production & set-up *plus* other net proceeds. The net cumulative balance is carried forward to the next period.

4.6.2 An OSR Project with Processing Facilities

Figure 3: An oil sands royalty project with processing facilities



Project Output

This type of project produces cleaned crude bitumen or other oil sands products.

Allowed Costs

Costs attributed to the production *and* cleaning or processing of crude bitumen are deducted as allowed costs. The cost rules for non-arm's-length capital assets apply. (see 9.1.2, "Capital Assets")

Royalty Calculation Point

This is at the outlet of the processing plant.

Project Royalty

Pre-payout royalty is 1% of the project's gross revenue—that is, 1% of the quantity of each oil sands product delivered at the royalty calculation point.

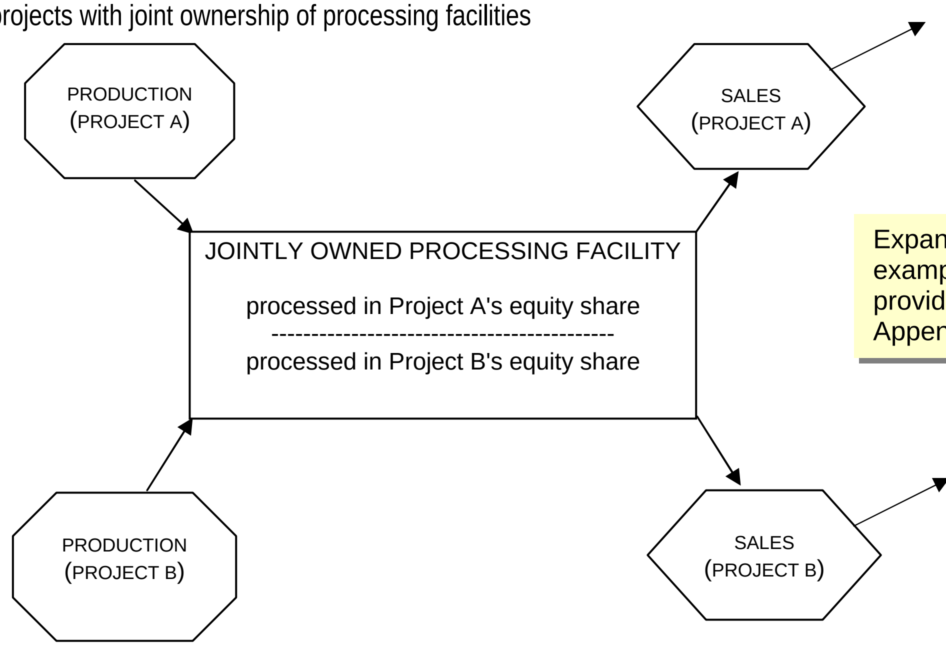
Post-payout royalty is the greater of 1% of the project's gross revenue or 25% of the net revenue for the period.

Net Cumulative Balance

This is the sales revenue *less* allowed costs attributable to production & set-up and processing *plus* other net proceeds. The net cumulative balance is carried forward to the next period.

4.6.3 OSR Projects with Jointly Owned Facilities

Figure 4: Two projects with joint ownership of processing facilities



Expanded example provided in Appendix K

Project Output

This type of project produces cleaned crude bitumen or other oil sands products.

Allowed Costs

Each project can deduct allowed costs attributed to production *and* to the proportion of processing costs that corresponds to their ownership share in the facility. The processing done for each project is assumed to be in proportion to the project's share of the processing facility. For example, if each project owner owns a 50% share, the processing for each project is assumed to be 50%.

If the processing is not in the same proportion as the ownership, a cost equalization payment is made to account for the difference. The cost equalization payment ensures that one owner is not covering costs for the other when royalty is calculated. The cost equalization payment is treated as a custom processing charge. (see 9.1.2, "Capital Assets")

If a processing facility that is wholly or partly owned by a project participant (or affiliate) is not included in the project description, the custom processing service provided by the facility is considered a basic service. The cost rules for non-arm's-length capital assets apply. (see Chapter 9, "Cost Rules Associated with Non-Arm's-Length Transactions")

Royalty Calculation Point

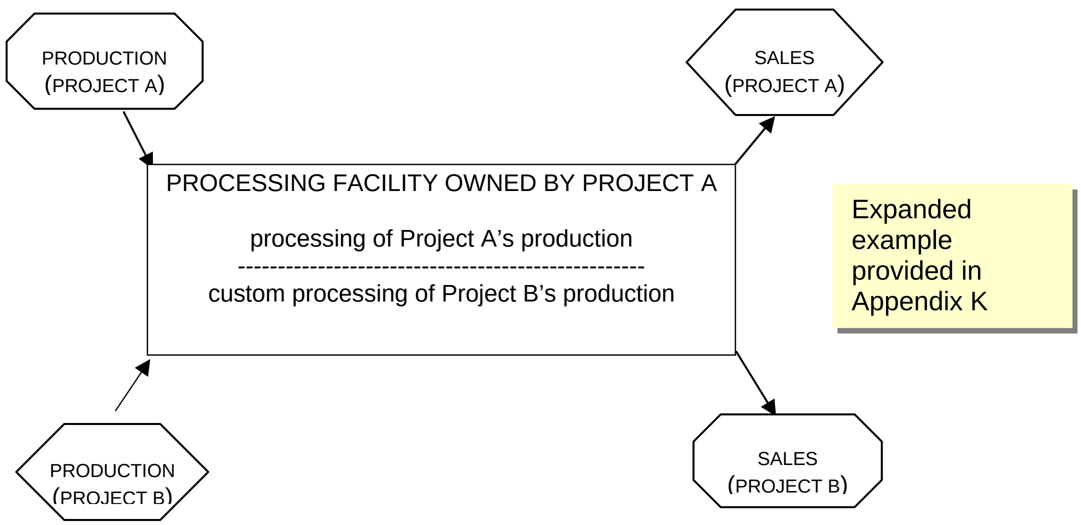
This is at the outlet of the processing plant.

Net Cumulative Balance

For each project, this is the sales revenue *less* allowed costs attributable to production & set-up and to the project's proportion of processing *plus* other net proceeds. The net cumulative balance is carried forward to the next period.

4.6.4 An OSR Project that Provides Custom Processing Services

Figure 5: An oil sands royalty project with processing facilities that processes the output (production) from another project



Project Output

This type of project produces cleaned crude bitumen or other oil sands products.

Costs and Revenues

Each project can deduct allowed costs attributed to production. Project A, as the owner of the processing facility, can also deduct all allowed costs attributed to processing. For Project A, revenues from custom processing fees are other net proceeds, which are deducted from allowed costs in calculating the project's net revenue. For Project B, the custom processing fees paid to Project A are an allowed cost.

If a processing facility that is wholly or partly owned by a project participant (or affiliate) is not included in the project description, the custom processing service provided by the facility is considered a basic service. The cost rules for non-arm's-length capital assets apply. (see Chapter 9, "General Non-Arm's Length Rules")

Royalty Calculation Point

This is at the outlet of the processing plant.

Net Cumulative Balance

For Project A, this is the sales revenue *less* allowed costs attributable to production and processing *plus* other net proceeds, which reduce allowed costs.

For Project B, this is the sales revenue *less* allowed costs attributable to production and processing *plus* other net proceeds. Allowed costs include the custom processing fees.

5. Specific Cost Allocation Rules

5.1 Solution Gas and Fuel Gas

Many oil sands projects use natural gas for fuel in their project operations. In some cases, the fuel gas must be imported into the project. In other cases, it is obtained from solution gas produced as a result of project operations.

Solution gas is natural gas that is dissolved in crude bitumen under initial reservoir conditions. Oil sands agreements issued on or after January 1, 2000, grant the rights to oil sands and to the solution gas they may contain.

For some oil sands royalty projects, solution gas gathering and distribution systems are necessary for the production and processing of bitumen: as such, they may be allowed costs in the OSR project – assuming also that there is no sale of the solution gas. In some cases, the solution gas produced in association with oil sands is used as fuel for project facilities; in other cases, the solution gas is sold and becomes subject to royalty payable under the Natural Gas Royalty Regulation, 2002.

Note

> The rules governing the treatment of capital and operating costs of equipment in oil sands royalty projects used to gather, compress or treat solution gas that is sold is the subject of the Solution Gas and Off Lease Fuel Gas Task Force operating under the Oil Sands Royalty Steering Committee. Resolution of the issue is expected in 2005, and these guidelines will be updated to reflect the business rules as approved by the Department.

5.2 Pipeline Services

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 7.3(1) to 7.3(7)

Pipelines for transporting bitumen (or blended bitumen) to market—that is, from a royalty calculation point to the point of disposition—are called non-basic pipelines because the service they provide is not needed for the production of clean crude bitumen—the minimum output required of any oil sands royalty project (see *section 21(4)* of the Regulation).

Under the terms of the Regulation, non-basic pipelines cannot be included as part of an oil sands royalty project description. However, charges for the use of such pipelines can be deducted from the unit price of the oil sands product. (see 5.2.1, "Calculating Allowed Costs for Non-Basic Pipeline Services") The total charge that can be claimed is the sum of the operating costs plus the capital costs per m^3 of capacity. Both costs are based on the portion of pipeline throughput that pertains to the project.

In some cases, project owners may also deduct a portion of the cost of oil purchased to “fill” the pipeline. (see 5.2.2, “Line Fill Costs")

5.2.1 Calculating Allowed Costs for Non-Basic Pipeline Services

The calculation of allowed costs for non-basic pipelines depends on whether or not a fair market value can be established for the use of the pipeline:

- If the pipeline is owned by the oil sands royalty project owner or by an affiliate, and if the Department can establish the fair market value of the pipeline service, the allowed cost is the *lesser of* the amount charged to the project or fair market value.
- If the Department cannot establish fair market value, the allowed cost is the *lesser of* the amount charged to the project or the actual cost incurred, as determined by a cost-of-service calculation.

For a definition of fair market value, see 9.1.4, "Fair Market Value".
For details about cost-of-service calculations for pipelines, see 5.2.1.2 "Allowed Costs Based on Cost-of-Service Calculations".

5.2.1.1 Allowed Cost Based on Fair Market Value

The fair market value of non-basic pipeline services can be approximated by using a regulated tariff charge for pipeline services.

When there is no regulated tariff, the Department may use a published tariff charged by the pipeline owner—if the following rules apply:

- The tariff is paid by shippers who are not affiliated with the pipeline owner.
- The tariff is fair and non-discriminatory.
- The pipeline is subject to complaints-based regulation.

When pipeline tariffs are not available, or when no comparable service exists, the fair market value of non-basic pipeline services can be approximated by the weighted average of prices paid by shippers who are not affiliated with the pipeline owner. The following rules apply:

- The pipeline is subject to complaints-based regulation.
- The weighted average price is fair.
- At least two-thirds of the volume of oil sands product shipped on the pipeline is owned by shippers who are not affiliated with the pipeline owner.

What is Complaint-based Regulation?

> A pipeline is subject to regulation on a complaints basis if a customer or potential customer can, by filing a complaint with a regulatory authority, initiate a review and modification of the terms of the pipeline service and charges.

5.2.1.2 Allowed Costs Based on Cost-of-Service Calculations

In the case of a non-basic pipeline providing transportation of oil sands products from a project, if a fair market value can be determined for the transportation service, the pipeline charge allowed for a unit price deduction will be the lesser of:

(a) the amount charged to the project; or

(b) fair market value.

- The cost-of-service calculation is based on a project's capital investment in the pipeline.
  - A net approach is used: each project owner calculates the pipeline charge for his project based on his portion of the pipeline's capital cost. (A gross approach would be based on the total capital cost of the pipeline.) For details, see Example 1 in this section.
- The pipeline's allowed capital costs are depreciated on a 5% straight-line basis over its useful life. For royalty calculation purposes the useful life of a pipeline is estimated to be at least 20 years.
- There is no floor on the undepreciated capital balance used to determine the return on capital. That is, the asset is depreciated until the remaining undepreciated balance is zero.
- The following formula is used to calculate the allowed rate of return on capital (RORC).

$$\text{RORC} = \left(\begin{array}{l}\text{Deemed Debt}\\\text{Percentage}\end{array}\right)\left(\begin{array}{l}\text{Deemed Cost}\\\text{of Debt}\end{array}\right) + \left(\begin{array}{l}\text{Deemed Equity}\\\text{Percentage}\end{array}\right)\frac{\text{Deemed Cost of Equity}}{\text{(1-Deemed Corporate Income Tax Rate)}}$$

Deemed Debt Percentage = 45%

Deemed Equity Percentage = 55%

Deemed Cost of Debt = Long-Term Bond Rate plus 1%

Deemed Cost of Equity = the annual multi-pipeline rate, as published by the National Energy Board.

This formula incorporates the deemed corporate tax rate and so yields a pre-tax weighted average cost of capital. Since corporate income taxes are included within this formula, no additional provision for corporate income taxes should be included in the pipeline's revenue requirement.

- The capital structure and corporate income tax rate may be revisited at the Department's discretion, or when there are significant market or tax changes.

Additional cost rules apply to

- sales of pipelines (see 5.2.3 "Cost Rules for Sales of Pipelines")
- pipeline overcapacity (see 5.2.4 "Cost Rules for Pipeline Overcapacity")
- capital additions to pipelines (see 5.2.5 "Cost Rules for Capital Additions to Non-Basic Pipelines")

Example 1

Assumptions:	Calculation:
- The pipeline is in its 5th year of operations. - Total capital cost is $90 million; - One owner's share is 50%; - The calculated rate of return on capital (RORC) in year 5 is 12.92% - Total throughput in year 5 is 55 million barrels, of which the owner owns 50% (27.5 million barrels)	- Owners capital cost is (50% of $90 million) = $45 million; - Depreciation charge is ($45 million / 20 years) = $2.25/year; - Undepreciated capital in year 5 is $45 million - (2.25 million * 5 years) = $33.75 million; - The per barrel capital charge would be equal to the capital rate base multiplied by the rate of return plus the period depreciation, divided by throughput:

$$\frac{\$33.75 \text{ million} * 12.92\% + 2.25 \text{ million}}{27.5 \text{ million barrels}} = \$0.24/\text{barrel}$$

Example 2

When a project's throughput exceeds the project's share of the capacity of the pipeline, the cost of the excess throughput is allocated to the project according to the actual amount charged by the other pipeline owners. This is because the excess throughput represents an arm's-length transaction.

Assumptions:	Calculation:
- In the previous example, assume that in 5 years, the owner uses 35 million barrels of capacity on the NAL pipeline, rather than the allocated 27.5 million; - The second owner's actual amount charged is $1.75 / barrel.	- The first owner's share of throughput, 27.5 million barrels, will be charged a capital charge of $0.24/barrel, plus operating costs based on the owner's share of throughput; - The additional (35 million - 27.5 million) = 7.5 million barrels will be charged $1.75/barrel for a total of $13.13 million; - The $13.13 million will be the pipeline tariff charge for the first project owner, and will be recorded as an Other Net Proceed for the second project owner.

5.2.2 Line Fill Costs

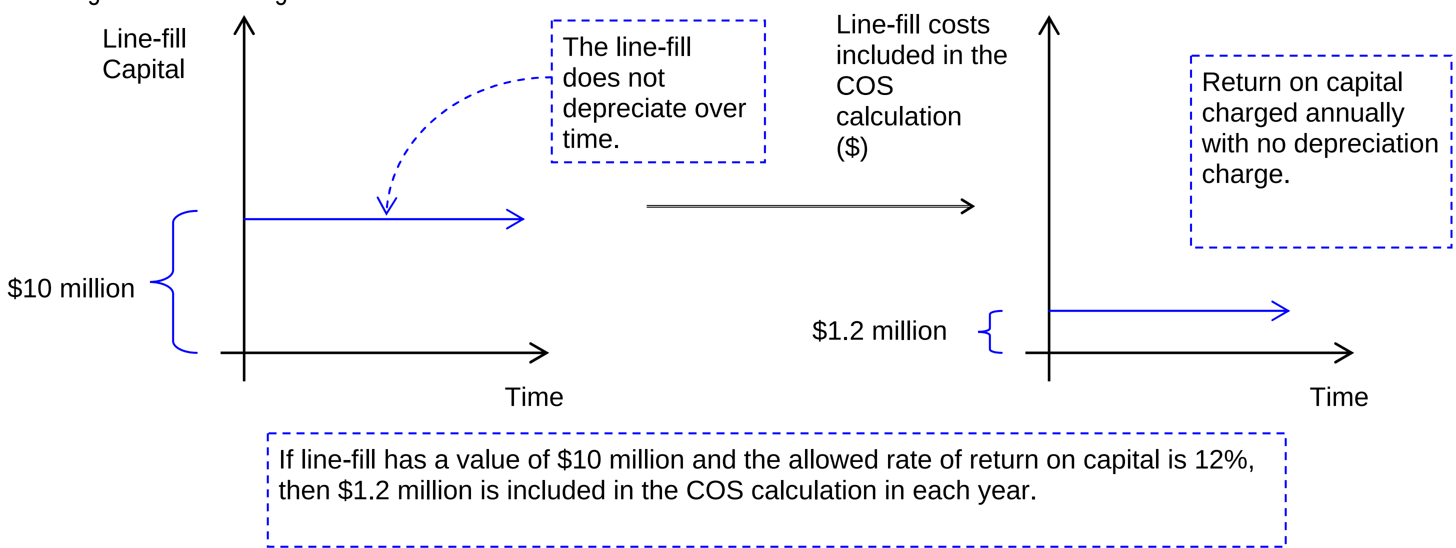
In addition to the cost of service, project owners may deduct a portion of the cost of the oil volumes purchased to “fill” the pipeline. The line fill volume is valued at the price at which it was acquired. Its return rate (RORC) is the same as the return rate allowed for the cost-of-service calculation. The following cost rules apply:

- Line fill is treated as inventory.
- The value of the line fill is its purchase cost, not its market value.
- The cost of service calculation does not include the original purchase cost. Only a return on capital (i.e., the original purchase cost of the line fill) is allowed. The return rate (RORC) is calculated as follows:

$$\text{RORC} = \left(\text{Deemed Debt Percentage}\right)\left(\text{Deemed Cost of Debt}\right) + \left(\text{Deemed Equity Percentage}\right)\frac{\text{Deemed Cost of Equity}}{(1-\text{Deemed Corporate Income Tax Rate})}$$

- Revaluations of line fill costs are not allowed.

Figure 6: Calculating line fill costs



5.2.3 Cost Rules for Sales of Pipelines

If a project-owned pipeline is sold or transferred, and if the sale price is higher than the pipeline's undepreciated capital cost, a new third-party toll must be established. The new pipeline toll is adjusted to reflect the pipeline's sale price. This ensures that the Crown does not pay for capital costs it already paid for through pre-sale cost-of-service depreciation.

The new, post-sale pipeline toll (used as a unit price deduction) is adjusted by the difference between the sale price and the undepreciated value of the pipeline. This amount is called the sale price premium. The adjustment factor is the flat-rate, dollars-per-volume toll that makes the pipeline's net present value (NPV)—given the expected pipeline throughput—equal to the sales price premium over the remaining expected life of the oil sands project.

The adjustment factor is calculated at the time of the pipeline sale and applies for the life of the project. Corrections can be made if the Department finds that estimates made with regard to project life or pipeline throughput were inaccurate.

Calculating the Adjustment Factor

1. The original pipeline owner determines
   - the sale price premium (sale price minus the pipeline's undepreciated capital at the time of the sale)
   - the remaining expected life of the oil sands project at the time of the sale
   - the estimated throughput for the pipeline's remaining expected life
2. The Department of Energy reviews and approves these determinations.
3. The pipeline owner calculates the toll adjustment factor that will be used to calculate the unit price.

$$\text{Adjustment factor } (\$/m^3) = \frac{\text{Estimated annual value of the sale price premium}}{\text{Estimated annual throughput}}$$

For example

Assumptions:

- A NAL non-basic pipeline subject to a COS calculation is sold to an unaffiliated 3rd party for $27.5 million;
- The pipeline's undepreciated capital at the time of the sale is $22.5 million;
- The sale is made in year 15 of the oil sands project, which has an expected life of 40 years;
- Pipeline throughput is 55 million barrels per year;
- The 3rd party discount rate is 12.92%; and
- The 3rd party toll is $0.200/barrel.

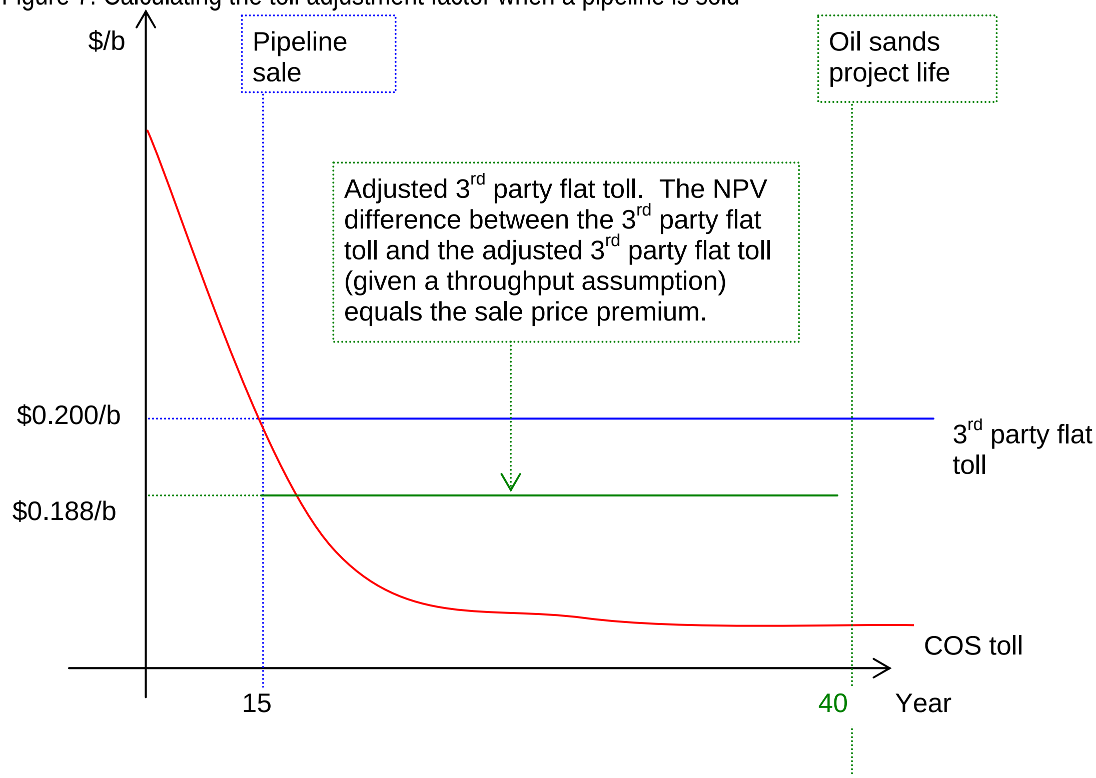
Calculation:

- The sale price premium is (27.5 – 22.5) = $5 million;
- The remaining life of the oil sands project is (40 – 15) = 25 years;
- The equivalent annual value is $678,531/year ($678,531/year for 25 years raises an NPV (@ 12.92% discount rate) equal to the sales price premium of $5 million);
- The adjustment factor (per barrel) is the equivalent annual value divided by throughput:

$$\frac{\$678{,}531/\text{year}}{55 \text{ million barrels/year}} = \$0.012/\text{barrels}$$

Figure 7, the post-sale pipeline toll is $0.188/barrel. This is the pre-sale toll ($0.200/barrel) less the adjustment factor ($0.012/barrel).

Figure 7: Calculating the toll adjustment factor when a pipeline is sold



5.2.4 Cost Rules for Pipeline Overcapacity

Oil sands project owners may build pipelines that are oversized in relation to the needs of the project. Overcapacity pipelines accommodate relatively lower throughput levels. This increases the Crown's share of risk by creating higher costs and higher unit price deductions for the duration of the oil sands project.

If an OSR project owner's share of a non-basic pipeline is subject to a cost of service calculation, and if the pipeline's annual volume is less than 150% of the EUB–approved capacity for the owner's project, the full annual capital depreciation is charged against the owner's cost of service, in each year.

If annual volumes are greater than 150% of the pipeline's approved capacity, the following cost rules apply:

1. The OSR project or pipeline owner chooses what percentage of the pipeline is considered project related. The chosen percentage must be justified by a business case and approved by the Department.

2. The annual capital depreciation charged against the cost of service is prorated based on the percentage of the pipeline that is project related.

$$\text{Annual capital depreciation (\$/year)} = \frac{\text{(Owner's share of undepreciated capital x Percentage of the pipeline that is project related)}}{\text{Expected life of the pipeline}}$$

3. The declared project-related percentage of pipeline use is subject to review by the Department if circumstances change.

For example

Assumptions:	Calculation:
- A NAL non-basic pipeline subject to a COS calculation has capacity of 55 million barrels per year; - The undepreciated total cost of the pipeline is $90 million; - The expected life of the pipeline is 20 years; - One owner’s share is 50%, or 27.5 million barrels per year; - AEUB approval for the owner is 10 million barrels per year.	- The owner elects and justifies that 50% of its share, or 13.75 million barrels per year, is identified as a “project pipeline”. - The annual capital depreciation charged is 50% of the owner’s share of capital (50% of $90 million = $45 million), straight-line over 20 years:

$$\frac{\$45\text{ million} * 50\%}{20\text{ years}} = \$1.13\text{ million/year}$$

5.2.5 Cost Rules for Capital Additions to Non-Basic Pipelines

Two types of capital costs are used in cost-of-service calculations for non-basic pipelines:

- capital costs for repairs or maintenance
- capital costs for material and non-material enhancements
  - For a capital cost to be considered material, it must be more than 10% of the original capital cost of the pipeline. It must also extend the life of the pipeline or increase pipeline capacity.

All capital costs for repairs or maintenance are eligible in the year in which the expenditure was incurred.

All capital costs that are not material are eligible in the year in which the expenditure was incurred.

Material capital costs are treated in one of two ways:

- If the cost is less than the pipeline’s undepreciated capital pool balance, it is added to balance and depreciated over the remaining life of the pool.
- If the cost is greater than the pipeline’s undepreciated capital pool balance, it is added to the pool and the whole pool is depreciated over a new 20-year period—that is, for the pipeline’s expected life.

For example

Assumptions:	Calculation:
- A NAL non-basic pipeline subject to a COS calculation had an original total cost of $90 million; - The expected life of the pipeline is 20 years; - In year 15, an additional $25 million of capital is spent on the pipeline.	- The capital expenditure is material ($25 million > 10% of $90 million); - Depreciation is $4.5 million per year; - In year 15, the undepreciated capital for the pipeline is $22.5 million; - The capital addition is material ($25 million > $22.5 million), so the total is depreciated over 20 years:

$$\frac{\$25 \text{ million} + \$20 \text{ million}}{20 \text{ years}} = \$2.25 \text{ million/year}$$

5.3 Cogeneration Plants

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 7.1(4)(a)

Cogeneration facilities use a single fuel source—usually natural gas—to produce both thermal and electrical energy. Steam produced from burning natural gas provides heat for oil sands project purposes. It also drives turbines that produce electricity for oil sands project purposes or sale.

Determinations of allowed costs related to cogeneration plants take into account the amount of steam or electricity used by the project and the percentage of the plant that is owned by project owners.

5.3.1 Valuing Steam and Electricity

Good or Services?

> The *Oil Sands Royalty Regulation, 1997,* section 7.1(4) defines the provision of thermal energy and the transmission and distribution of electricity as services.
>
> Electricity itself is defined as a good. Natural gas is also considered to be a good.

Basic services (see 9.2.2 "Basic Services") are valued on a cost-of-service basis.

Goods are valued on a fair market value basis whenever this is possible. When a representative fair market value is not available, cost-of-service valuation is used instead.

Department business rules recognize the unique characteristics of steam and electricity production. The provision of steam and electricity are inextricably linked in a cogeneration plant. As a result, the valuation methodology addresses the provision of combined heat and power (CHP).

5.3.1.1 Fair Market Value–Based Valuation for Electricity

The fair market value of electricity is calculated by using a simple average of the prices of market instruments used in electricity-related transactions. A multiple price-based approach should reduce the volatility of any single market instrument.

The prices used to calculate a fair market value must be readily available and appropriate. The following principles apply:

1. The price is associated with a market instrument that is publicly traded and reported.

2. The instrument is used for ongoing transactions for the delivery of electricity within a current period. A one-time transaction or a finite series of historical transactions is not appropriate.

3. Ideally, for periods of less than one month, there are no reporting gaps. If gaps exist, they should not introduce any bias with regard to the instrument's price.

4. The price represents an arm's-length transaction.

5. The price is quantifiable as an electricity cost. It does not include the cost of transmission or system support services and is not based on heat rates.

6. The instrument's price is charged to the delivery month rather than the month when electricity was purchased.

7. The calculation of fair market value should include as many prices as possible: i.e., the prices of all instruments that meet the principles listed above.

The preceding seven rules provide for a process that

- is straightforward and transparent
- eliminates the need to decide on arbitrary weightings in the absence of volume information, and
- uses a simple average to reduce price distortions

The following formula is used to calculate fair market value for electricity:

$$FMV = \frac{\sum_{i=1}^{n} P_i}{n}$$

i	=	the number of available prices (The value of i ranges from 1 to n, where n is the total number of prices available)
Pi	=	the price of instrument i
FMV	=	fair market value

The simple average approach is appropriate because a publicly available traded price is sufficient, and there is no need for a specific volume to be traded to constitute a liquid and fair market. Each valid price will have an equal weighting within the average regardless of how much volume is traded in that instrument, the number of trades, or the number of traders (i.e., the volume traded would not have an effect on whether the price calculated represented a fair market value or not. Monthly prices will better reflect variations in the different instrument markets.

The calculation of the monthly value for each component will vary. For example, the Power Pool price would be the published monthly average Pool price for each month. For forward components, the price will be set to reflect the settlement price for each instrument. For example, the “Next Calendar Year” for 2003 would be that set on the last trading day of 2002: the month is set at the last trading day of the previous month, etc. Day Ahead, Balance of the Month, and Rest of Calendar Year would all use an average of prices. Some forward prices may need further examination to ensure they meet the principles, such as "balance of month" and "rest of year".

Examples of fair market value calculations

Example #1 - General

Instrument Prices ($/MWh)	**Description**	**Jul**	**Aug**	**Sep**
Pool Average	Average of prices for month	26.41	32.03	45.70
Day Ahead	Average of prices from last day of previous month to second last day of current month	30.33	29.59	47.98
Balance of Month	Average of prices from beginning to last day of the month	31.97	31.89	43.10
Prompt Month	Settlement price in the previous month	35.00	35.06	41.50
Prompt Month+1	Settlement price from two months previous	39.25	37.40	35.15
Prompt Quarter	Settlement price from the previous quarter	36.00	36.00	36.00
Prompt Quarter+1	Settlement price from two quarters previous	47.75	47.75	47.75
Prompt Quarter+2	Settlement price from three quarters previous	n/a	n/a	n/a
Rest of Year	Average of prices from beginning of year to end of month	40.89	40.64	41.37
Next Calendar Year	Settlement price from previous year	38.50	38.50	38.50
Electricity FMV		**36.23**	**36.54**	**41.89**

Given the prices of the different instruments, the fair market value of electricity would be $36.23, $36.54 and $41.89 per MWh for July, August and September 20__, respectively. If another price became available, it would be included in the average as follows:

In example #2, the additional price has caused only a slight change to the fair market value.

EXAMPLE 2 - Additional Price Available

Instrument Prices ($/MWh)	**Description**	**Jul**	**Aug**	**Sep**
Pool Average		26.41	32.03	45.70
Day Ahead		30.33	29.59	47.98
Balance of Month		31.97	31.89	43.10
Additional Price	------------------------->	**36.59**	**39.15**	**45.02**
Rest of Year		40.89	40.64	41.37
Next Calendar Year		38.50	38.50	38.50
Electricity FMV		**36.27**	**36.80**	**42.21**

As shown in the following example, using a simple average approach reduces price fluctuations that may arise within any one trading instrument. In this example, August's pool price is significantly higher than July's. September's pool price is the same as August's, while the prompt month contract is much higher. Significantly higher values for one price component generally result in a small increase in fair market value.

Note

Since volumetric trading information is not generally available, fair market value–based electricity valuation does not include

- minimum volumes that would eliminate some prices
- calculations based on volumes traded

EXAMPLE 3 - Higher Prices

Instrument Prices ($/MWh)	Description	Jul	Aug	Sep
Pool Average	---------------------------->	26.41	**65.21**	45.70
Day Ahead		30.33	29.59	7.98
Balance of Month		31.97	31.89	43.10
Prompt Month	---------------------------->	35.00	35.06	**78.21**
Next Calendar Year		38.50	38.50	38.50
Electricity FMV		**36.23**	**40.23**	**45.97**

5.3.1.2 Cost of Service–Based Valuation for Electricity and Steam

Electricity produced outside an oil sands project is considered a good, not a service, and is therefore subject to fair market value considerations. If fair market value can be established, there is no need to use a cost-of-service approach. If there is no fair market value, the value of electricity is subject to cost-of-service determinations.

Steam, whether produced inside or outside a royalty project is defined as a basic service: therefore, a cost-of-service approach is needed to value the steam depending on whether it was obtained from inside or outside the project.

The cost-of-service calculation for steam and electricity uses a modified version of the methodology applied to NAL non-basic pipelines. A fundamental principle of all cost-of-service determinations is that the oil sands project should not subsidize the cost of non-project operations. The use of capital and operating cost allocation methods mitigates the risks of cross-subsidization.

Example 1

Consider an oil sands project that includes steam facilities within the project and electricity facilities outside.

- The steam costs are part of the project's allowed cost base and are treated the same way as other allowed costs. No cost-of-service determination is required.
- The electricity costs would be allowed at fair market value, if one could be determined. Only if a fair market value could not be established would a cost-of-service approach be necessary.

Example 2

Consider an oil sands project that uses steam and electricity facilities that are not part of the project.

- Steam costs would be calculated using a cost of service approach. The allowed rate of return would be the same long-term bond rate used in calculating the project's return allowance.
- The electricity costs would be allowed at fair market value, if one could be determined. Only if fair market value could not be established would a cost-of-service approach be necessary.

5.3.1.3 Valuing Steam and Electricity from a Cogeneration Plant

The following rules apply to non-arm's-length, natural gas–turbine-powered cogeneration plants equipped with heat-recovery steam generators (HRSG). The rules recognize that cogeneration plants provide both heat and power to oil sands projects. The determination of allowed costs includes consideration for their combined effect.

1. **If the steam-generating portion** of the cogeneration plant **is outside** the oil sands project, the cost of service must be determined—just as if the plant was a stand-alone steam generator. The long-term bond rate is used for the rate of return on capital.

2. **If the steam-generating portion is inside** the oil sands project, capital and operating cost allocations are determined in the same manner as if the steam portion was outside the project, regardless of how electricity is valued. (see 5.3.5.1, "Steam")

3. **When the electricity-generating portion** is outside the oil sands project, and when fair market value for electricity cannot be established, a cost of service approach is used to value the electricity. The long-term bond rate (LTBR) is used to calculate the rate of return on capital. The deemed cost of debt is the LTBR plus 1%:

the deemed cost of capital is the LTBR plus 4%. The deemed debt / equity ratio is 30% / 70 % (see 5.3.5.2, "Electricity".)

4. **When capital, operating, and other annual non-fuel-related cost allocations** are split between the steam- and electricity-generating functions of the plant, the following rules apply:

- All capital, operating and annual non-fuel costs incurred upstream of the point where hot air is transferred to the HRSG are allocated to electricity. That is, the gas turbine and generator are allocated as electricity costs; the HRSG is not.
- All capital, operating and annual non-fuel costs incurred downstream of the point where hot air is transferred to the HRSG are allocated to steam. That is, the HRSG is allocated as steam-related costs; the gas turbine and generator are not.

5. **Fuel allocations** in cost-of-service determinations for steam vary depending on whether a fair market value can be established for electricity. The same rules for fuel allocations apply whether the steam is generated inside or outside the royalty project.

If a fair market value for electricity exists, NAL steam and electricity are charged at the lesser of the following:

- Electricity is charged at fair market value, and steam on a fuel-charged-to-steam (FCS) basis assuming a heat recovery steam generator operating with a thermal efficiency of 85%, or
- Electricity at actual amount charged to the project, and steam on a FCS basis in accordance with the calculations described on in 5.3.1.3.1, "Sample Calculations".

If there is no fair market value for electricity, steam and electricity are charged at the lesser of the following:

- Electricity at cost of service with fuel charged to power (FCP) equal to all fuel (gas turbine and duct fired) minus FCS, and steam on a FCS basis assuming a thermal efficiency of 85%; or
- Electricity at actual amount charged to the project; and steam on a FCS basis in accordance with calculations described in 5.3.1.3.1, "Sample Calculations".

The "lesser of" rule will only apply when the operator has appropriately demonstrated the required measurement for calculations described in 5.3.1.3.1, "Sample Calculations", i.e. if the formula cannot be used, then FCS will always be at a thermal efficiency of 85%.

For the first cases in both of the above scenarios, the FCS of 85% reflects the average fuel used (i.e., thermal efficiency) to generate steam in once through steam generators (OTSG), and ensures that the steam side of the project is no worse off cost-wise by using a HRSG. The remainder of the fuel balance, i.e., the amount of the gas turbine (GT) fuel and duct-firing portion not included in FCS, is allocated to electricity. The allowed cost of electricity to the project is based on an electricity COS determination, if there is no fair market value for electricity.

For the second cases in both of the above scenarios, when FCS is determined according to the "formula", the amount of sensible heat captured by the HRSG from the GT exhaust, the amount of duct firing and the amount of HRSG flue gas use allocated to steam must all be defined. This test uses the actual value of electricity charged and a COS determination for steam that has fuel allocated according to the formula.

Under the formula, if there is no duct firing, the fuel is allocated assuming a HRSG efficiency of 86% (this is intended to approximate the 85% value use under the first case). When there is duct firing, the formula is dynamic giving the steam side a possible uplift (lower fuel cost when the HRSG is duct fired with high efficiency) as well as a downside, but still within a reasonable range of expectations.

5.3.1.3.1 Sample Calculations

The following calculation-steps illustrate the "fuel charged to steam" formula. Electricity is valued at the actual amount charged. Steam-related costs are determined by using a cost-of-service calculation.

1. Calculate the portion of the sensible heat captured in the steam resulting from duct firing in the generator. (HRSG)

   – Multiply the actual (measured) volume of duct-firing fuel by the actual (measured) HRSG efficiency.

2. Calculate the portion of the sensible heat captured in the steam resulting from the gas turbine fuel.

   – Subtract the amount calculated in Step 1 from the total actual (measured) sensible heat.

3. Calculate the portion of the energy in the HRSG flue gas charged to steam.

   – (3.1) determine the portion of the energy in the HRSG flue gas resulting from duct-firing fuel:

Subtract the amount calculated in Step 1 from the total actual (measured) volume of duct-firing fuel.

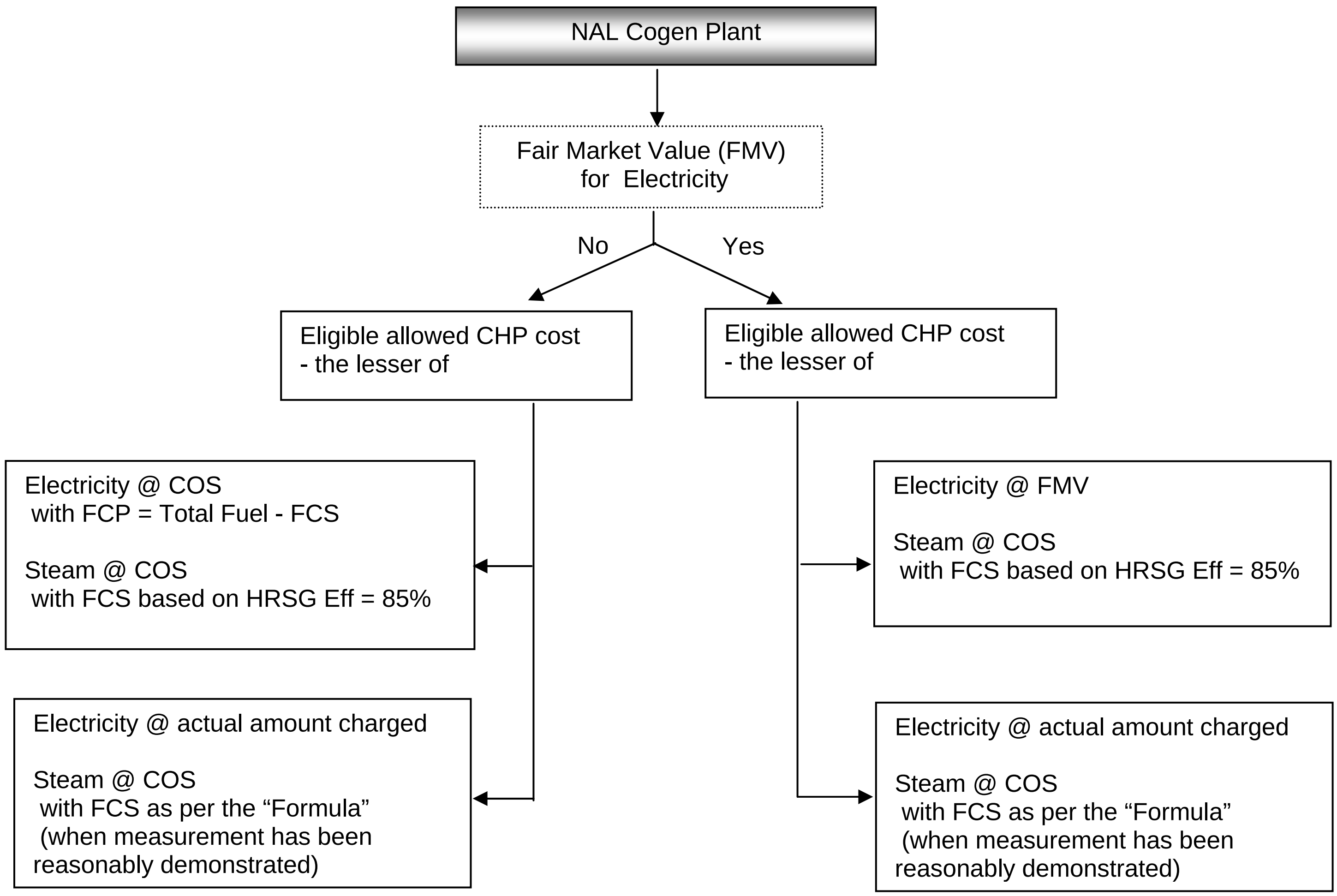
- (3.2) determine the portion of the energy in the HRSG flue gas resulting from gas turbine fuel:
  Subtract the amount calculated in Step 3.1 from the total actual (measured) volume of HRSG flue gas.
- (3.3) determine the percentage of sensible heat in the steam:
  Divide the amount calculated in Step 2 by the total, measured gas turbine fuel.
- (3.4) determine the portion of turbine-related generator flue gas energy that should be charged to steam:
  Multiply the amount calculated in Steps 3.2 by the amount calculated in Step 3.3.

4. Calculate the gas turbine fuel portion of the fuel charged to steam:
Add the results of Step 2 and Step 3.4.

5. Calculate the duct-firing fuel portion of the fuel charged to steam.

6. Determine the total volume of fuel charged to steam:
Add the results of Step 4 and Step 5.

Figure 8: Allowed costs for non-arm's-length cogeneration



Abbreviations Used:

CHP - Combined Heat and Power
COS - Cost of Service
Eff - Efficiency
FCP - Fuel Charged to Power
FCS - Fuel Charged to Steam
FMV - Fair Market Value
HRSG - Heat Recovery Steam Generator

FUEL CHARGED TO STEAM (FCS) CALCULATIONS w/r HRSG EFFICIENCIES (fired & unfired)

Data inputs in **blue** based on measured and manufacturer's data
Sensitivity changes reported in the Summary Table are determined by **red** inputs

Manufacturer's Data (GJ/day)

	Unfired HRSG	Fired HRSG
GT fuel	24,735	24,735
Steam sensible heat	10,149	18,239
HRSG flue gas	4,138	4,901
Duct firing fuel	-	8,853
HRSG efficiency	71%	79%

NOTE: the formula was run with different HRSG efficiencies that encompasses the experience with actual operations. Industry has suggested that a unfired HRSG (no duct firing) efficiency of 71% is reasonable, and 79% for a fired HRSG.

SUMMARY TABLE

Unfired HRSG Efficiency	Unfired FCS Efficiency	Fired HRSG Efficiency	Fired FCS Efficiency
95%	86%	95%	89%
90%	86%	90%	88%
85%	86%	85%	86%
80%	86%	80%	85%
75%	86%	79%	85%
71%	86%	75%	84%
70%	86%	70%	83%
65%	86%	65%	82%
60%	86%	60%	81%
55%	86%	55%	80%
50%	86%	50%	80%
45%	86%	45%	79%
40%	86%	40%	78%

STEPS	Formula with Unfired HRSG			Formula with Fired HRSG		
1	**Steam sensible heat from duct firing**		—	**Steam sensible heat from duct firing**		6,994
	Duct firing fuel	-		Duct firing fuel	8,853	
	HRSG efficiency	71%		HRSG efficiency	79%	
	Steam sensible heat from duct firing	—		Steam sensible heat from duct firing	6,994	
2	**Steam sensible heat from GT**		10,149	**Steam sensible heat from GT**		11,245
	Total steam sensible heat	10,149		Total steam sensible heat	18,239	
	Less duct firing sensible heat	-		Less duct firing sensible heat	6,994	
	Steam sensible heat from GT	10,149		Steam sensible heat from GT	11,245	
3	**HRSG flue gas chargable to steam**		1,698	**HRSG flue gas chargable to steam**		1,383
	Duct firing fuel	-		Duct firing fuel	8,853	
	Duct firing sensible heat	-		Duct firing sensible heat	6,994	
3.1	Duct firing loss	-		Duct firing loss	1,859	
	HRSG flue gas	4,138		HRSG flue gas	4,901	
	Duct firing loss	-		Duct firing loss	1,859	
3.2	Flue gas loss due to GT	4,138		Flue gas loss due to GT	3,042	
	Steam sensible heat form GT	10,149		Steam sensible heat form GT	11,245	
	Total GT fuel	24,735		Total GT fuel	24,735	
3.3	Sensible GT heat/ GT fuel	41%		Sensible GT heat/ GT fuel	45%	
	Sensible GT heat/ GT fuel	41%		Sensible GT heat/ GT fuel	45%	
	Flue gas loss due to GT	4,138		Flue gas loss due to GT	3,042	
3.4	HRSG flue gas chargable to steam	1,698		HRSG flue gas chargable to steam	1,383	
4	**Total FCS from GT**		11,847	**Total FCS from GT**		12,628
	Steam sensible heat from GT	10,149		Steam sensible heat from GT	11,245	
	HRSG flue gas chargable to steam	1,698		HRSG flue gas chargable to steam	1,383	
	Total FCS from GT	11,847		Total FCS from GT	12,628	
5	Total FCS from duct firing		—	Total FCS from duct firing		8,853
6	**TOTAL FCS:**		11,847	**TOTAL FCS:**		21,481
	Total FCS from GT	11,847		Total FCS from GT	12,628	
	Total FCS from duct firing	-		Total FCS from duct firing	8,853	
	TOTAL FCS:	11,847		TOTAL FCS:	21,481	
	FCS Efficiency (financial measure)		86%	**FCS Efficiency (financial measure)**		85%
	Total steam sensible heat	10,149		Total steam sensible heat	18,239	
	Total FCS	11,847		Total FCS	21,481	
	Total steam / total FCS	86%		Total steam / total FCS	85%	

5.3.2 Allocating Capital and Operating Costs

A steam or electricity plant running at or above 85% capacity is considered to be operating at its base load (that is, at or near its capacity). When the annual capacity factor is greater than or equal to 85%, annual capital costs are applied on throughput.

Operating costs are based on throughput, so the average operating cost profile remains the same no matter the end user. When the annual capacity factor is below 85%, the project is subject to review at the Minister's discretion.

Annual Capacity Factor

> This ratio is calculated by dividing actual energy or steam produced annually by the amount of energy or steam the plant would have produced had it operated at its maximum continuous rating for the whole year.

5.3.3 Shared Costs

The capital and operating costs of shared facilities, such as the operating control room for stand-alone steam plant, stand-alone electricity power plants, or cogeneration plants, is to be allocated to steam and electricity in proportion to the capital cost of the facilities incurred directly for each of their respective "unshared" or single purpose facilities.

5.3.4 Depreciation

Steam and electricity plant capital are depreciated on a 5% straight-line basis over 20 years.

The Minister has the discretion to review and modify this rate as required. See OSR'97 section 7.1(2)(c)(i).

5.3.5 Rate of Return on Capital

5.3.5.1 Steam

Steam is a basic service. As a result the allowed rate of return on capital (RORC) is the long-term bond rate (LTBR). The same rate would apply for royalty purposes if the steam facility were treated as part of the oil sands project.

5.3.5.2 Electricity

The allowed rate of return on capital (RORC) is calculated using a pre-tax weighted average cost of capital formula, as follows:

$$\text{RORC} = \left(\begin{matrix}\text{Deemed Debt}\\ \text{Percentage}\end{matrix}\right)\left(\begin{matrix}\text{Deemed Cost}\\ \text{of Debt}\end{matrix}\right) + \left(\begin{matrix}\text{Deemed Equity}\\ \text{Percentage}\end{matrix}\right)\frac{\text{Deemed Cost of Equity}}{\text{(1-Deemed Corporate Income Tax Rate)}}$$

Deemed Debt Percentage = 30%

Deemed Equity Percentage = 70%

Deemed Cost of Debt = Long-Term Bond Rate plus 1%

Deemed Cost of Equity = Long-Term Bond Rate plus 4%

Deemed Capital Structure = 30% debt and 70% equity

Deemed Corporate Income Tax Rate = the rate the owner applies to the asset on his tax return

5.3.6 Cost Rules for Sales of Cogeneration Plants

If a project-owned cogeneration plant is sold or transferred, and if the sales price is higher than the plant's undepreciated capital cost, a new charge-out rate must be established. This ensures that the Crown does not pay for capital costs it already paid for through pre-sale cost-of-service depreciation.

The new rate reflects the difference between the sales price and the undepreciated value of the plant. This amount is called the sale price premium. The adjustment factor is the flat rate that makes the plant's net present value (NPV) equal to the sale price premium.

The adjustment factor is calculated at the time of the plant sale and applies for the life of the project. Corrections can be made if the Department finds that the estimates regarding project life or plant output were inaccurate.

5.3.6.1 Calculating the Adjustment Factor

When a cogeneration plant is sold, its charge-out rate is adjusted at the time of sale. The following business rules apply:

1. The original plant owner determines
   - the sales price premium
   - the remaining expected life of the oil sands project at the time of the plant sale
   - the estimated output of the plant for the remaining expected life of the oil sands project

2. The Department of Energy reviews and approves these determinations.

3. The plant owner calculates the annual charge-out rate adjustment factor that will be used to calculate the price. This calculation only needs to be made once.

$$\text{Adjustment factor } (\$/m^3) = \frac{\text{Estimated annual value of the sale price premium}}{\text{Estimated annual plant output}}$$

The discount rate in the adjustment factor calculation is determined using the methodology to calculate the allowed rate of return on capital for NAL plants subject to a cost of service calculation, under the Regulation. Special Circumstances: Selling a Plant Together with Other Assets

If a cogeneration plant is sold together with other assets, the parties involved in the transaction prepare a sales agreement that assigns a value to each asset. The Department of Energy may challenge the assignment of asset values by using the dispute resolution and appeals process (see Chapter 8, "Dispute Resolution and Appeals"). Federal tax authorities may challenge the valuation in court.

5.4 Custom Processing

If a project asset is used to provide non-arm's-length custom processing services to other oil sands royalty projects, the non-arm's length rules in Chapter 9 apply.

5.5 Hedges

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 10(b)

Hedges are financial instruments that reduce the risk of investments or other financial transactions. They use actual commodities and financial derivatives such as futures, contracts and swap arrangements to counterbalance price fluctuations and protect the investment.

When commodities are used as hedges, details about the item that is sold or purchased (or delivered or received) are typically specified in a contract. This contract may be based on spot prices or on a longer-term, fixed price. A separate contract may arrange to mitigate (hedge against) commodity price or currency fluctuations that may result from the original contract. Gains or losses can occur.

Gains or losses or costs that result from the hedging of oil sands products cannot be included as allowed costs. However, hedging transactions related to direct project costs incurred by or on behalf of the project owners are allowed if the following conditions are met:

- When hedges are made, project operators must notify the Department about their policy on hedging.
- Hedges must relate to costs that are directly attributable to the project. Hedges for speculative purposes are not allowed.

- The gains and losses and the costs associated with the hedging transaction must be clearly documented. Project-related commodities, goods or currency must be clearly identified.

Hedging costs are, of course, still subject to the criteria in *section 2 of Schedules 1 and 2* of the Regulation.

5.6 Research

Since research is critical for the continued competitiveness of Alberta's oil sands, certain research costs can be claimed as allowed costs.

5.6.1 Cost Rules for Research

Oil Sands Royalty Regulation, 1997 (AR 185/97), schedule 1, section 2(e)(ix), re non-qualifying joint ventures

Oil Sands Royalty Regulation, *1997* (AR 185/97), schedule 2, section 2(e)(ix), re qualifying joint ventures

To be eligible for deduction as allowed costs, research costs must comply with the following rules:

- The research must be reasonable and have a specific, practical, project-related application.
  - Research can be undertaken at off-site labs as long as it is directly related to project activities.
- Research costs must be directly attributable to the oil sands royalty project
  - The scope of allowable research costs is determined by the project description. For example, if an approved project includes an upgrader, research costs that are directly attributable to that upgrader may be eligible.
- Research costs must be incurred by or on behalf of the project owners
- Research costs must be incurred and paid after the date on which the project was approved
  - Research costs incurred before a project's effective date may, within the parameters of section 18 of the Regulation, be included in determining the project's **prior net cumulative balance**. (see 2.3.10, "Prior Net Cumulative Balance")
- Claimed research costs must reflect an actual financial transaction that is supported by documentation.
  - Project operators should be prepared to provide sufficient information to support the claim of eligibility for research costs.

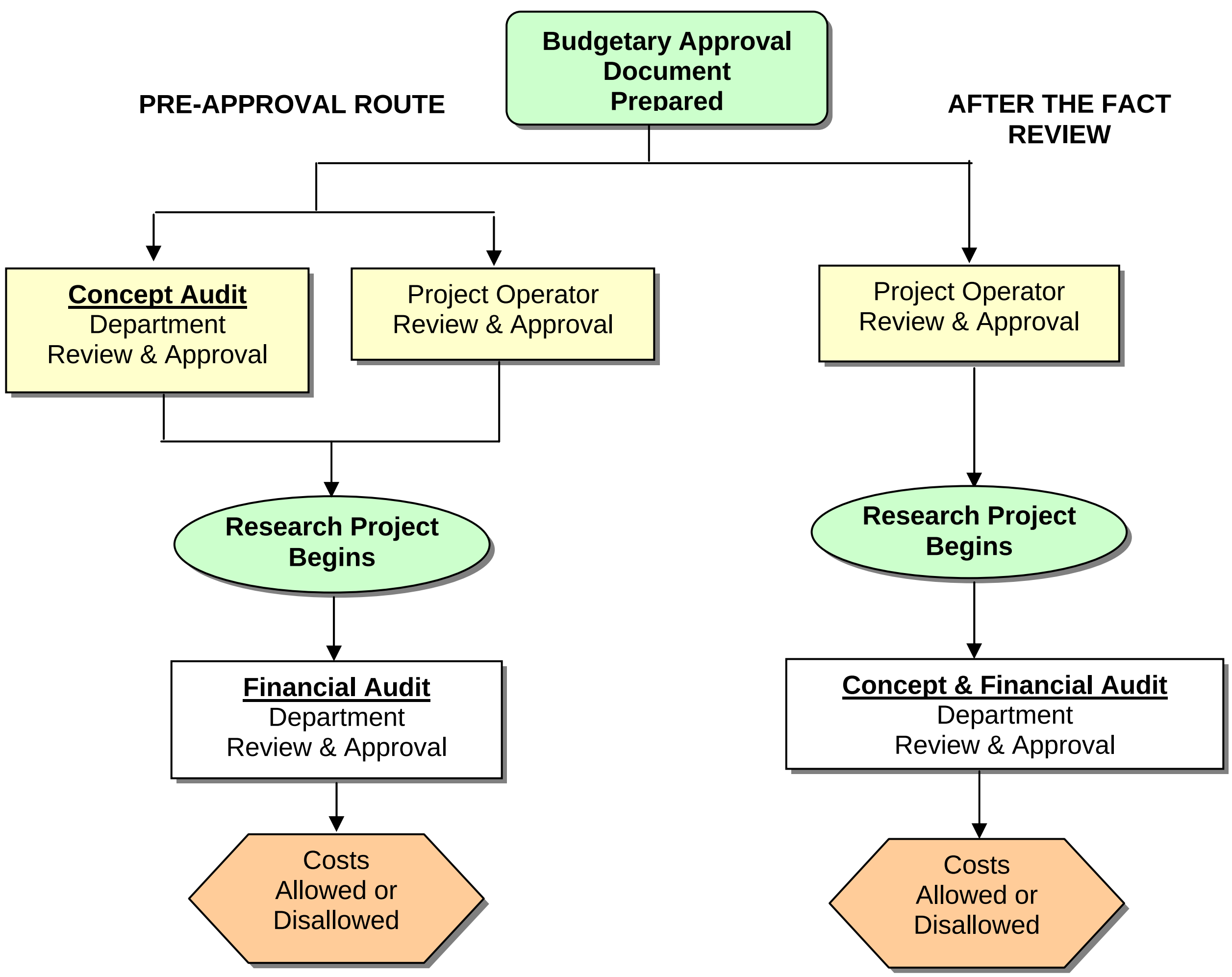
- Only net research costs are allowed.
  - With the exception of income tax reductions, all credits or discounts that reduce actual research costs must be deducted from the project's allowed costs. This includes credit for research received from other programs in Alberta or from any other jurisdiction in which the research is recognized. (If such credits or discounts were not recognized, the benefit would be counted twice.) See *section 3(j)(ii) of Schedules 1 and 2*.
- Project owners, who recover research costs from other industry participants, must include the recovered amounts as "other net proceeds" (see 4.2.3.1, "Types of Revenue"). This ensures that the research costs are only counted once. Non-basic research costs may be eligible both as deductions against royalties under the *Oil Sands Royalty Regulation, 1997* and as deductions against escalating rental payments under the *Oil Sands Tenure Regulation.* Note, however, that the royalty and escalating rental deductions are not required to be applied proportionally to the same leases.

Auditing Research Costs

All research costs claimed by an oil sands royalty project are subject to concept and financial audits conducted by the Department. A financial audit is conducted once a concept audit has found the research costs to be eligible, and once the costs have actually been incurred.

For details about financial audits, see 6.8, "Financial Audits". For details about concept audits, see 5.6.4, "Concept Audits".

Figure 9 - Approving and auditing research projects



5.6.2 Examples of Allowed Research Costs

Project operators are encouraged to request a concept audit (see 5.6.4, "Concept Audits") before undertaking research activities. This minimizes the risk that expenditures will be disallowed during financial audits conducted by the Department.

The following types of costs may be eligible as allowed costs:

- market research related to project planning and design
- costs incurred to support a specific consortium research activity that has direct applicability to the oil sands project
  - Funding a specific, university-based project in order to receive the research data and conclusions is an example of an eligible consortium research activity
- basic research for qualifying joint ventures

What is basic research?

Basic research is research designed to gain general knowledge or understanding rather than to address a specific technological challenge.]

5.6.3 Examples of Research Costs That Are Not Allowed

- basic research for non-qualifying joint ventures
- research-related management and membership fees
- market research to determine upgrader requirements
- costs related to non-arm's-length transfers of proprietary research or proprietary technology, including research publications and licensed research or technologies

5.6.4 Concept Audits

Concept audits verify that a proposed or current research project or activity is directly attributable to an oil sands royalty project. For example, an OSR project owner may wish to conduct applied research that is marginally applicable to the project. If a concept audit concludes that such research is not "directly attributable," as required by the Regulation, the cost of the research is ineligible as an allowed cost. Alternatively, if the audit concludes that some or all of the research is directly attributable to the project, a corresponding portion of the research cost is eligible as an allowed cost.

Concept audits are conducted on two occasions:

- at the planning stage of a research project, when a project owner has submitted a request for an advance ruling (see Chapter 7, "Advance Rulings") to pre-approve a proposed research project
  - Project owners are advised to coordinate their requests for a pre-approval with their own, corporate approval processes. This facilitates Department–owner discussions and consensus about the purpose of the proposed research project.
  - A budgetary approval document should be submitted with the request.
- as part of a financial audit (see 6.8, "Financial Audits") conducted by the Department

In conducting a concept audit, the Department considers

- how the research advances knowledge which has specific, practical application to the project
  - The research does not have to be successful. However, for research costs to be eligible as allowed costs, the research must demonstrate the potential to provide meaningful insight or understanding of a problem or issue that is directly related to the oil sands royalty project.
- the type and nature of deliverables
- the location of the research activity
  - Off-site research may be eligible. Supporting documentation must be provided to show why an off-site location is preferable, especially if the research is being conducted in facilities outside Alberta.
- whether or not the research findings will be applicable within a reasonable time frame
  - The rule of thumb is that research should be applicable within five years of the date when a research project is first launched. Longer time frames may be approved if the project operator can provide a business case to support the extension.

5.6.5 Claiming Research Costs

To claim research costs, the OSR project operator must submit a budgetary approval document—such as an authorization for expenditure form—that supports the link between the corporate decision to undertake a specific research activity and the actual expenditure and results. The approval document creates a paper trail that facilitates the Department's audit process and ensures accountability.

The budgetary approval document must be signed by the corporate officer authorizing the expenditures. It must include the OSR project approval number and the legal description of the oil sands leases to which research costs are to be allocated. It must also describe:

- the purpose of the research and demonstrate that it is directly attributable to the project, as required by the Regulation
- the nature of the research project and its scope, including any external approvals that may be required
- the research participants
- the research time frame
- expected deliverables and due dates
- the location of research
  - Supporting rationale must be provided if the lease is located outside Alberta.
- the planned expenditures
  - The categories of research costs must be itemized. Allocations to capital or operating budgets must be identified and annual and cumulative amounts must be provided.
- any financial support which is being provided through Alberta programs or from other jurisdictions

A budgetary approval document must be submitted to the Department even if the research project was pre-approved.

6. Royalty Reporting and Payment

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 27 to 34

The Crown's royalty share is calculated and paid monthly at the rate prescribed by the Regulation:

- For **pre-payout projects**, the applicable royalty is 1% of the project's gross revenue.
- For **post-payout projects**, the applicable royalty is the greater of
  - 1% of the project's gross revenue, or
  - 25% of the net revenue for the **period**

Royalty reporting requirements depend on whether or not a project has reached payout—the first day of the month during which its cumulative revenues equal its cumulative costs. (see 4.3, "The Royalty Calculation for Pre-Payout Projects" and 4.4, "The Royalty Calculation for Post-Payout Projects")

What is a period?

> *Section 1(u)* of the Regulation defines a period as each **calendar year** that occurs between the project's effective date and the date when project approval is revoked.
>
> When a project reaches payout part way through the year, two periods are used for reporting purposes. The last day of the pre-payout period is the day before the post-payout period begins.

What is a month?

> *Section 3* of the Regulation defines a month, except as otherwise specified by the Minister, as the period of time that begins at 8:00 AM on the first day of the month and ends immediately before 8:00 AM on the first day of the next month.

6.1 Reporting Requirements for Pre-Payout Projects

Both pre-payout and post-payout projects must submit an operator's forecast each year.

6.1.1 Monthly Royalty Calculation Reporting Forms (MRC)

The monthly royalty calculation is submitted to the Department on the appropriate reporting form (MRCs). The following project information is required:

- project identification, as itemized in the table on 6.4.1.1, "Required Information"

- the sales volume and sales revenue, and the sales price per volume for each oil sands product
- the net volume and net price of all crude bitumen sold that month
- the volume of crude bitumen produced for the month
  - For a project that is subject to a unit agreement, Crown and freehold production volumes must be reported separately, as indicated on the form.
- the unit price
  - All handling charges must be reported in order to calculate the unit price. (see 4.2.4, "Unit Price")

Because the unit price is different for each oil sands product, a separate MRC must be completed for each product.

- the volume and cost of any diluent included in the sales product
- The appropriate portion of diluent cost is deducted from the Crown's royalty share.

An executive officer (e.g., controller or chief financial officer), or authorized delegate, of the operator must sign the MRC. The individual who completed the report must be identified and contact information (e-mail address and telephone number) must be provided. The date the report was prepared must also be indicated.

Each reporting form is itemized below and a sample is provided in the Appendix. All reporting forms are available for download on the Departments website.

- MRC-1a Pre-payout Monthly Royalty Calculation (Blended Bitumen)
- MRC-1b Pre-payout Monthly Royalty Calculation (Bitumen)
- MRC-1c Pre-payout Monthly Royalty Calculation (Synthetic Crude Oil)
- MRC-1d Pre-payout Monthly Royalty Calculation (Other Oil Sands Products)

6.1.1.1 Amendments

A project operator may submit an amended MRC if the original submission's data was subject to an adjustment. **MRCs cannot be amended after the Department has accepted an end of period statement for the project.** Although the amount of royalty payable may change when the report is amended, the due date for payment remains unchanged. If the adjustment results in an underpayment, interest would be calculated starting the day after the royalty was payable. For example, royalty for oil sands products sold or disposed of in April is due on May 31 even if an amended report is submitted after this date. Interest on an underpayment would be calculated as of June 1.

The Crown does not pay interest on royalty overpayments made by the operator, whether the overpayment was made on an original or an amended MRC.

6.1.1.2 Timing

Oil Sands Royalty Regulation, *1997 (AR 185/97), section 28*

Pre-payout monthly royalty calculations must be submitted by the last day of the month following the production month. For example, production and royalty for April would be reported by May 31. Penalties and interest may be levied if pre-payout monthly reports are submitted late, or improperly completed. (see 6.6, "Penalties" and 6.7, "Interest".)

6.1.2 End of Period Statement Reporting Forms (Pre-Payout)

End of period statements detail project operations from both a financial and a production perspective. These statements are a comprehensive package which must be signed by an executive officer of the project operator and include project identification information, as itemized in the table in 6.4.1.1, "Required Information".

Each reporting form contained in the package is described below and a sample is provided in the Appendix. All reporting forms are available for download on the Departments website.

6.1.2.1 Contents of Pre-Payout Reporting Package

6.1.2.1.1 Auditor's Letter Requirement (PRE-1)

A letter from an independent auditor is required if the project's crude bitumen sales average more than 1,590 m^3 per day during the period. If sales are less than the 1,590 m^3 per day threshold, statements prepared by project operators are sufficient.

If an independent audit is required, the auditing firm must provide a signed letter verifying that, in the firm's opinion, the project operator has complied with the requirements of the Regulation.

If the project reached the 1,590 m^3 per day threshold, the external auditor's opinion applies only to the current period cost and revenue portion of the statements, and not to the opening cumulative balance. However, since both the opening balance and the current period amounts affect the project's return allowances, the auditor must acknowledge that the opening amounts were not examined.

All end of period statements—whether they were independently audited or not—are subject to financial audits conducted by the Department. (see 6.8, "Financial Audits")

6.1.2.1.2 Project Payout Status (PRE-2)

This reporting form summarizes the cumulative cost and cumulative revenue for prior periods, adds the allowed costs (including the cost of diluent), project revenue and other net proceeds for the current period, and determines the net cumulative balance of the project.

The operator must also provide an estimated payout date for the project and identify the assumptions that underlie the estimate. The assumptions pertain to

- sales price
- price differential
- production volumes
- Canadian exchange rate

6.1.2.1.3 Allowed Costs Summary (PRE-3, PRE-3a and PRE-3b)

These reporting forms report the allowed costs incurred in the following categories:

- operating costs
- capital costs
- diluent costs
- royalty paid
- return allowance earned

Project operators must also provide cost details—using the formats provided in supplementary forms PRE-3a and PRE-3b or equivalent in-house reporting forms. Cost detail reports must include the following information

- costs per month
- costs per category (as listed at the start of this section) and subcategory
  - Project operators may define their own subcategories to reflect the nature of their particular operations. For example, operating costs may include staff costs, repairs and maintenance, fuel costs and other subcategories that reflect the project's operations.

6.1.2.1.4 Return Allowance (PRE-4)

The monthly return allowance earned (see 4.2.1, "The Return Allowance") is an allowed cost. Together with other allowed costs and royalty paid for that month, it is added to the previous month's cumulative cost to get the current cumulative cost for the project.

6.1.2.1.5 Revenue Summary (PRE-5)

This reporting form summarizes the total revenue generated for each month of the period. Sales revenue less all handling charges and less the cost of diluent determines the project's gross revenue. Other net proceeds are added to the gross revenue to determine the project's cumulative revenue.

Details for each number within PRE-5 are required to be reported on forms PRE-6a through PRE-6d. A revenue detail form is required for each leased oil sands product sold or disposed of by the project operator.

6.1.2.1.6 Royalty Summary (PRE-6)

This reporting form summarizes the Crown's royalty share payable for each leased oil sands product delivered to the royalty calculation point. The total royalty payable for the period should equal the total royalty actually paid by the operator. Penalties and interest may apply.

Details about the royalty share payable for each leased oil sands product are reported on forms PRE-6a through PRE-6d.

6.1.2.1.7 Royalty Detail (PRE-6a to PRE-6d)

These reporting forms provide details to support the royalty-related figures reported on the revenue and royalty reporting forms (PRE-5 and PRE-6). A royalty detail form is required for each leased oil sands product sold, used or disposed of by the project operator. This is because each product has a different unit price.

- Blended bitumen sales are reported on form PRE-6a.
- Bitumen sales are reported on form PRE-6b.
- Sales of synthetic crude oil are reported on form PRE-6c.
- Sales of other oil sand products are reported on form PRE-6d.

These forms include details about sales volume, sales revenue and handling charges in order to calculate the unit price for each product.

6.1.2.2 Amendments

The production, revenue and royalty figures reported on an end of period statement must match those submitted on the pre-payout project's monthly reports. **Monthly pre-payout reports cannot be amended after the Department has accepted an end of period statement.**

The Department will not accept amendments to end of period statements after the filing deadline. If new financial information becomes available after this date, and if the information results in a significant royalty adjustment, the operator should immediately notify the Department, in writing. The adjustment should be reported on the next end of period statement.

6.1.2.3 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), section 29*

End of period statements must be submitted within three months of the end of each period. For example, if the period ends on December 31, the end of period statement must be submitted by March 31 of the following year. Penalties and interest may be levied if end of period statements are submitted late. (see 6.6, "Penalties" and 6.7, "Interest")

6.2 Reporting Requirements for Post-Payout Projects

Monthly royalty calculations are submitted to the Department on a good faith estimate (GFE) form. The financial information required on a GFE is more detailed than the information reported on the monthly royalty calculation form (MRC) submitted for pre-payout projects. Actual figures for past months and estimates for future months must be included.

Both pre-payout and post-payout projects must submit an operator's forecast each year. (see 6.3, "The Operator's Forecast")

Each reporting form is described below and a sample is provided in the Appendix. All reporting forms are available for download on the Departments website.

6.2.1 Monthly Good Faith Estimates Reporting Forms (GFEs)

For post-payout projects, good faith estimates (form GFE-1) are submitted each month. Like the monthly reports submitted for pre-payout projects, good faith estimates provide project identification, contact and royalty calculation information. The latter information is more comprehensive than that required for pre-payout reports.

The GFE provides financial details for each month during the period. This includes actual figures for the current and past months and estimated figures for future months.

Accurate estimates must be provided: the estimates directly affect the amount of royalty estimated and remitted for the period.

Monthly good faith estimates include the following details:

- project identification, as itemized in the table in 6.4.1.1, "Required Information"
- the actual or estimated production of crude bitumen and a calculation of its net price
  - The crude bitumen net price is realized revenue less the cost of diluent over the quantity of crude bitumen, blended bitumen (less diluent volume) and synthetic crude oil disposed of.
- the sales volume and sales revenue for each oil sands product disposed of
- the unit price for each leased oil sands product
  - All handling charges must be reported in order to calculate the unit price. (see 4.2.4, "Unit Price")
- the project revenue
  - The project revenue is the sum of all leased oil sands products less their respective handling charges. This amount is used to calculate the net revenue. The project revenue less the cost of diluent determines the gross revenue.
- allowed costs
  - Allowed costs are categorized as

- *plant operations*
- *diluent (The weighted average cost of diluent included with blended bitumen is deducted from the Crown's royalty share.)*
- *capital*
- *net loss carried forward*

▪ other net proceeds

- Allowed costs can be reduced by the total amount of other net proceeds earned by the project, but the reduction claimed cannot exceed the original amount of the allowed costs.
- If other net proceeds exceed allowed costs, the allowed costs are reduced to zero and the unused portion of the other net proceeds is carried forward to the next period as an allowed cost. The excess is carried forward until it is depleted.

▪ the project's net revenue or net loss

- If a net loss occurs, it is carried forward to the next period as an allowed cost.

A senior representative, or authorized delegate, of the operator must sign the GFE. The individual who completed the report must be identified and contact information (e-mail address and telephone number) must be provided. The date the report was prepared must also be indicated.

6.2.1.1 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), section 28*

Good faith estimates must be submitted by the last day of the month following the production month. For example, production and royalty payable for April would be reported by May 31. Penalties and interest may be levied if pre-payout monthly reports are submitted late.

Exceptions

> Newly approved or amended projects normally have retroactive effective dates. For example, a project approved in March might have an effective date of January. In this case, monthly reports for January, February and March would be due by April 30th. Due dates for subsequent monthly reports would follow the regular schedule.

6.2.2 End of Period Statements Reporting Forms (Post-Payout)

End of period statements detail project operations from both a financial and a production perspective. These statements are a comprehensive package which must be signed by an executive officer and include project identification information, as itemized in the table in 6.4.1.1, "Required Information".

Each reporting form contained in the package is described below and a sample is provided in the Appendix. All reporting forms are available for download on the Departments website.

6.2.2.1 Contents of Pre-Payout Reporting Package

6.2.2.1.1 Auditor's Letter Requirement (PST-1)

A letter from an independent auditor is required if the project's crude bitumen sales average more than 1,590 m^3per day during the period. If sales are less than the 1,590 m^3 per day threshold, statements prepared by project operators are sufficient.

If an independent audit is required, the auditing firm must provide a signed letter verifying that, in the firm's opinion, the project operator has complied with the requirements of the Regulation.

All end of period statements—whether they were independently audited or not—are subject to financial audits conducted by the Department. (see 6.8, "Financial Audits")

6.2.2.1.2 Royalty Payable (PST-2)

This reporting form identifies the royalty payable and the royalty rate used to calculate this amount. (Royalty payable is the greater of 1% of the project's gross revenue or 25% of the net revenue.)

The total royalty payable for the period is reconciled to the total royalty actually paid by the operator. Any difference must be paid by the operator or refunded by the Department by the last day of the 4th month following the end of the period.

6.2.2.1.3 Royalty Calculations (PST-3)

This reporting form calculates royalty based on 1% of the project's gross revenue and on 25% of the net revenue. The greater of these amounts is the payable royalty, which is entered on form PST-2. If gross revenue royalty exceeds net revenue royalty, the excess is carried forward as an allowed cost for the next period.

The components used in the royalty calculation (project revenue, the cost of diluent, allowed costs and the allowable portion of other net proceeds) are derived from forms PST-4, PST-5 and PST-7.

6.2.2.1.4 Allowed Cost Summary (PST-4, PST-4a and PST-4b)

These reporting forms summarize the allowed costs incurred by the project. The costs are broken down into subsidiary categories. The following categories are mandatory:

- operating costs
- capital costs
- the cost of diluent
- the return allowance on the previous period's net loss

- the net loss carried forward from the previous period
- the excess gross revenue royalty paid in the previous period

Project operators must also provide cost details—using the sample formats in forms PST-4a and PST-4b or an in-house reporting format. Cost detail reports must include the following information

- costs per month
- costs per category (operating, capital and diluent) and subcategory
  - Project operators may define their own subcategories to reflect the nature of their particular operations. For example, operating costs may include staff costs, repairs and maintenance, fuel costs and other subcategories that reflect the project's operations.

6.2.2.1.5 Other Net Proceeds (PST-5)

This reporting form identifies other net proceeds generated by the project. The categories listed on the form are intended as examples: project operators may use categories that reflect their particular operations.

In a post-payout period, the amount of other net proceeds that can be used to reduce allowed costs cannot exceed the total amount of allowed costs. Any excess of other net proceeds over allowed costs is carried forward as a deduction against the allowed costs for the next period.

6.2.2.1.6 Return Allowance (PST-6)

This reporting form calculates the return allowance for the period. A return allowance is provided only when the project has a net loss at the end of a period. (see 4.2.1, "The Return Allowance")

6.2.2.1.7 Project Revenue (PST-7)

This reporting form summarizes the total revenue generated for each month of the period. Project revenue less the cost of diluent determines the gross revenue of the project.

Details for each number on this schedule are reported on forms PST-7a through PST-7d. A revenue detail schedule (similar to pre-payout form PRE-6a through PRE-6d) is required for each oil sands product sold or disposed of by the project operator.

6.2.2.1.8 Carry Forward Amounts (PST-8)

This reporting form identifies four cost and revenue amounts that can be carried forward to the next period as allowed costs:

- the net loss during the period
- the return allowance for current period's net loss
- the excess of gross revenue royalty over net revenue royalty

- the excess of other net proceeds over total allowed costs (carried forward to the next period's other net proceeds)

6.2.2.2 Amendments

The Department will not accept amendments to end of period statements after the filing deadline. If new financial information becomes available after this date, and if the information results in a significant royalty adjustment, the operator should immediately notify the Department, in writing. The adjustment should be reported on the next end of period statement.

6.2.2.3 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), sections 29*

End of period statements must be submitted within three months of the end of each period. For example, if the period ends on December 31, the end of period statement must be submitted by March 31 of the following year. Penalties and interest may be levied if end of period statements are submitted late.

6.3 The Operator's Forecast

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 27

Operators' forecasts are required for both pre-payout and post-payout projects. They are used to estimate oil sands royalty revenues that could be expected by the Crown for the current calendar year plus the next four years.

The Department recognizes that operators' forecasts are "best guesses" at the time they are submitted, and can vary significantly in the coming years. If a forecast has changed by more than ±20% during the course of a year, the operators must notify the Department.

Operator's forecasts must identify the opening balances for the current year and the project as a whole, and provide estimates of projected

- *sales volumes*
- *quality differentials*
- *handling charges*
- *other project revenues*
- *natural gas volumes used*
- *diluent volumes used*
- *allowed costs*
- *other net proceeds*

They must also forecast the expected payout date of any pre-payout project.

Operators are requested to include written explanations to interpret and clarify the figures submitted in the forecast.

Forecasts should be submitted to the Director, Evaluations, Oil Sands Development (See Appendix J, "Contact Information.")

6.3.1 Explanatory Notes

The numbers in the following text refer to numbers identified on the Department of Energy's "Sample Format for Operator's Forecast Report." (see the appendix for a sample copy.)

1. Units

   – All monetary values are reported in current year Canadian dollars.

   – Volumes are reported in cubic metres (m^3).

2. Current Year

   – **For projects with an effective date before October 31** of the current calendar year, current year information combines actual and projected revenues and expenditures:

– *actual figures are used for the period from the project's effective date to October 31 of the current calendar year*

– *forecasted figures are used for the period from November 1 to December 31 of the current calendar year*

   – **For projects with an effective date between October 31 and December 31** of the current calendar year, current year information includes forecasted information from the effective date to December 31 of the current calendar year.

Where actual values for current-year quality differentials and handling charges are unknown, estimates will be accepted.

3. Net Cumulative Balance

   – The following rules apply for projects with an effective date before January 1 of the current calendar year:

– ***If the project did not reach payout by December 31*** *of the year prior to the current calendar year, the net cumulative balance is as reported on the previous year's end of period statement.*

– ***If the project reached payout by December 31*** *of the year prior to the current calendar year, the net cumulative balance is, if applicable, the net loss carried forward from the period prior to January 1 of the current calendar year.*

– *For projects whose effective date falls within the current calendar year, the net cumulative balance is the prior net cumulative balance.*

4. Sales Volumes

   – Forecasts of sales volumes are required for each of the project's oil sands product streams, which may include crude bitumen, blended bitumen, synthetic crude oil or partially upgraded bitumen.

– *Oil sands products such as sulphur and coke are excluded from this section of the forecast: revenue from these products is recorded as "other product revenues."*

   – Products of reasonably similar quality may be combined into one product stream.

– *To provide the Department with an understanding of the product quality, the operator must provide an estimate of the average or range of API gravity and the percentage of sulphur content for each forecasted product stream.*

If more than 20% of the project's sales volumes are sold at a fixed price under a long-term contract (longer than 6 months), this portion is reported in terms of revenues rather than sales volumes.

5. Quality Differential

   – A forecasted quality differential is required for each reported product stream.

   – The quality differential—measured in dollars per m^3—compares the price of an oil sands product with the price of an appropriate benchmark crude oil. Either Edmonton Light Par or Hardisty Heavy is appropriate benchmarks for this purpose. The price of the benchmark crude must be reported as well as the quality differential.

   Quality Differential = Benchmark Price – Product Price

   – In calculating the quality differential, products of reasonably similar quality may be combined into one product stream. In this case, a weighted average is used to determine the quality differential.

6. Handling Charges

   – Handling charges must be reported—as dollars per m^3—for each reported product stream. Handling charges include export terminal charges and transportation from the royalty calculation point to the point of sale or to the export terminal (Edmonton, Hardisty and Lloydminster) closest to the project.

- The point of sale or export terminal must be identified. Transportation costs must be broken down into pipeline or trucking costs, as appropriate.

7. Other Product Revenues

- Other product revenues include the operator's forecast of revenues from oil sands by-products such as sulphur and coke.
- "Other product revenues" and "other net proceeds" are mutually exclusive.

8. Natural Gas Volumes Used

- Projects that use natural gas must report the volume used **unless** the natural gas is purchased under a long-term contract at a fixed price. In the latter case, the natural gas costs are captured as allowed costs and the volumes used do not need to be reported.

- When natural gas volumes are reported, operating costs figures (reported as allowed costs) must exclude natural gas costs.

9. Diluent Volumes Used

- If blended bitumen is reported, the volumes of diluent used in blending the bitumen must also be reported.

10. Allowed Costs

- Forecasts of both capital costs and operating costs are required.

- **Capital costs** must be classified as sustaining or strategic. Alternatively, total capital expenditures can be broken down by major capital projects, phases of expansions or some other appropriate division. (For the purpose of the report, strategic capital is generally defined as capital expenditures that are required to expand production capacity above the previous year's level. Sustaining capital would be all remaining capital expenditures.)

- **Operating costs** exclude the cost of diluent. They also exclude natural gas costs unless natural gas volumes are not reported.

11. Other Net Proceeds

- Other net proceeds include revenues from custom processing, cogeneration and other sources that are not related to the disposition of oil sands products.

12. Forecast of the Project Payout Date
    - Projects that have not yet reached payout must provide a forecast of the expected project payout date.

6.3.1.1 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), section 27*

Operators' forecasts must be submitted by December 15 of each year.

6.4 Reporting Formats and Timing

6.4.1 Forms

Royalty reporting forms can be downloaded from the Department website as PDF or Excel files. The latter included pre-programmed formulae so that the required calculations are done automatically once monthly volumes have been entered.

Sample reporting forms are included in the Appendix.

6.4.1.1 Required Information

The following table provides an at-a-glance-look at the project identification and signatures required on royalty reporting forms:

PREPAYOUT		POSTPAYOUT	
Monthly Royalty Calculation (MRC)	**End of Period Statement**	**Monthly Good Faith Estimate (GFE)**	**End of Period Statement**
▪ the project name	▪ the project name	▪ the project name	▪ the project name
▪ the oil sands project approval order number	▪ the oil sands project approval order number	▪ the oil sands project approval order number	▪ the oil sands project approval order number
▪ the production year and month	▪ the period start and end dates	▪ the production year and month	▪ the period start and end dates
▪ relevant EUB scheme numbers			
▪ the name and contact information for the person who completed the report		▪ the name and contact information for the person who completed the report	
▪ the signature of an approved financial officer	▪ the signature of an approved financial officer	▪ the signature of an approved financial officer	▪ the signature of an approved financial officer
▪ due by the last day of the month following the production month	▪ due within three months of the end of each period	▪ due by the last day of the month following the production month	▪ due within three months of the end of each period
▪ amendments can be made prior to the end of period statements being submitted	▪ amendments after the filing deadline are not allowed	▪ N/A	▪ amendments after the filing deadline are not allowed
	▪ auditor’s letter required if sales average more than 1,590 m^3/day		▪ auditor’s letter required if sales average more than 1,590 m^3/day

6.4.1.2 Reporting Standards

All royalty-related reports submitted to the Department must comply with the following standards.

6.4.1.2.1 Volumetric Reporting

Volumes of bitumen, diluent and synthetic crude oil are expressed in cubic metres (m^3) to the nearest tenth of a cubic metre. For example: 66.9 m^3

Quantities of sulphur are expressed in tonnes to the nearest tenth of a tonne.
For example: 34.9 t

6.4.1.2.2 Monetary Values

Monetary values are reported in Canadian dollars. The mathematical accuracy required for reporting monetary values is as follows:

- The unit price of oil sands products and diluent is expressed in dollar and cents to the nearest cent per unit. For example: $123.45 per unit
- Dollar amounts (except unit prices) reported on good faith estimates and end-of-period forms are expressed to the nearest dollar. For example: $123
- Dollar amount on pre-payout monthly royalty calculation forms shall be expressed in dollar and cents to the nearest cent. For example: $1,235.45

6.4.1.2.3 Negative Values

Negative values, whether monetary or volumetric, are indicated with a leading negative sign. For example: –$132.50 or –2,395 m^3

6.4.1.3 Submissions

Project operators may submit MRC or GFE reports to the Department in hard copy format or electronically.

If reporting is done electronically, the following rules apply:

- Reports must be submitted in the format prescribed in the Excel-format forms on the Department website.
- The date and time when the report was sent must be indicated on the submission.
- The software used to must be compatible with the version of Excel used by the Department. As of printing, this is Microsoft Excel 2003.
- Project operators must provide an appropriately signed paper copy of the end of period statements. An electronic copy would also be appreciated.

NOTE

The Department is not liable for report submissions that are lost in transit.

It is the responsibility of the project operator to ensure that project reports reach the Department by the specified due dates. The Department may impose penalties and interest if required reports are late. (see 6.6, "Penalties" and 6.7, "Interest".)

6.4.2 Timing

Oil Sands Royalty Regulation*, 1997 (AR 185/97), sections 27, 28 and 29*

Monthly royalty reports—including pre-payout MRCs (monthly royalty calculations) and post-payout GFEs (good faith estimates)—are due by the last day of the month following the production month. For example, production and royalty for April would be reported by May 31.

For newly approved or amended oil sands royalty projects that have retroactive effective dates, the first monthly report is due by the last day of the month following the month in which the project was approved. For example, a project approved in March might have an effective date of January. In this case, monthly reports for January, February and March would be due by the end of April. Due dates for subsequent monthly reports would follow the regular schedule.

End of period statements (for both pre- and post-payout projects) are due within three months of the end of each period.

Operators' forecasts are due by December 15 of each year.

Penalties and interest may be levied if the required reports are submitted late.

6.5 Royalty Payment

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 24, 25 and 31

6.5.1 Methods of Payment

All remittances of Crown royalty payment must be payable to the Minister of Finance, Province of Alberta.

Crown royalty can be remitted in four ways:

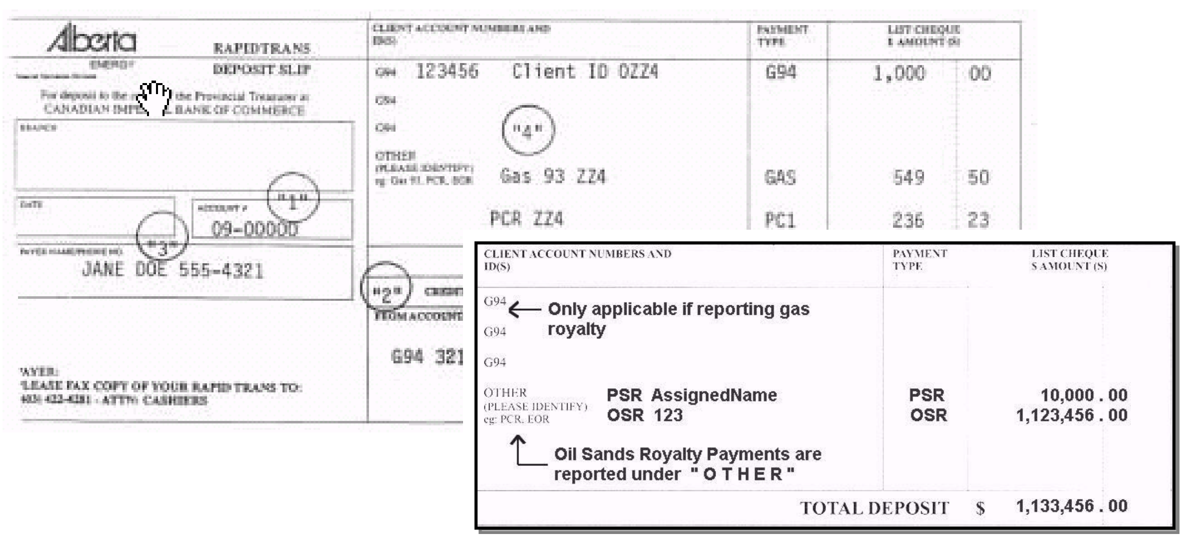
- by **cheque** through the mail or by courier
- by **electronic funds transfer** to the account of the Minister of Finance, Account 09-35603, at the Canadian Imperial Bank of Commerce.
- by automatic debit
- by **direct deposit**, using a RapidTrans deposit slip

- RapidTrans deposit slips are available from the Calgary Information Centre.
  at

Alberta Department of Energy
Calgary Information Centre
300, 801 - 6 Avenue SW
Calgary, Alberta Canada T2P 3W2

Telephone	(403) 297-8955
Fax	(403) 297-8954

Figure 10: The information required for oil sands royalty payments.



6.5.2 Required Information

Oil sands royalty payments must include the following information:

- *the payment date*
- *the name of the payer*
- *the activity ID that identifies the name or number assigned to the project*
- *the dollar amount for each activity ID, if the payment is for more than one project*
- *the payment total*

If the payment is made by direct deposit, the required information must be entered directly on the RapidTrans slip.

If the payment is by mail or electronic transfer of funds, the required information can be faxed to the Cashiers Financial Services Group at 780.422-4281.

6.5.3 Timing

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 31(1), 31(2) and 31(5)

For pre-payout projects, Crown royalty payments must be submitted by the last day of the month following the month in which the Crown's royalty share was disposed of, consumed or used. For example, if 300 m^3 of crude bitumen are produced in January but not sold until June 15, royalty is payable on or by July 31.

For post-payout projects, Crown royalty payments must be submitted by the last day of the month following the month in which the Crown's royalty share was disposed of, consumed or used. For example, if 300 m^3 of crude bitumen are produced in January but not sold until June 15, royalty is payable on or by July 31.

Interest is charged if monthly royalty payments are late.

6.5.4 Information and Assistance

For assistance in completing RapidTrans slips for oil sands royalty payments, contact Noelle Winter, Royalty Operations. (See Appendix J, "Contact Information")

For information about signing up for RapidTrans payments, contact the Department's Financial Services Branch.

6.6 Penalties

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 32

Penalties may be assessed against project operators who fail to provide the required operating forecast, monthly reports and end of period statements by the prescribed due dates. (see 6.4.2, "Timing")

A $1,000 penalty may be imposed for each month or partial month a report is late. Penalties must be paid within 30 days of receiving notice of the penalty.

Penalties may also be assessed against project operators who do not comply with the regulatory requirements specified in the Regulation. If a financial audit (see 6.8, "Financial Audits") conducted by the Department identifies a royalty underpayment, and if the auditor determines that the underpayment occurred as a result of improper record keeping, lax reporting procedures or non-compliance with the Regulation, the operator would be notified that the cause of the deficiency must be corrected.

If the same deficiency arises in a subsequent period, a penalty may be assessed. The penalty amount for the second instance is 10% of the resulting royalty deficiency. For any subsequent instance, the penalty would be 50% of the royalty deficiency. No penalty would be levied if the penalty amount is less than $1,000.

Penalties must be paid within 30 days of receiving notice of the penalty.

Penalty Waivers

> The Minister may waive a penalty assessed for non-compliance or for late reporting caused by circumstances agreed to be beyond the operator's control.

6.7 Interest

Oil Sands Royalty Regulation, 1997 (AR 185/97), section 33

6.7.1 Interest Charged by the Crown

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 33(1), 33(2) and 33(3)

Interest may be charged to project operators who fail to remit royalty or other payments to the Crown by the dates prescribed in the Regulation. The Crown may charge interest if the following payments are late:

- a monthly royalty payment
  - Interest on the outstanding amount is calculated from the day *following* the last day of the month following the production month.
- a royalty underpayment in respect of any month
  - Interest on the outstanding amount is calculated from the day *following* the last day of the month following the production month.
- a royalty underpayment identified in an end of period statement
  - Interest on the outstanding amount is calculated from the day *following* the end of the fourth month following the end of a period.

- royalty due as a result of a recalculation made as part of a financial audit conducted on behalf of the Crown
  - Interest is calculated from the date the royalty was initially due.
- penalties
- outstanding interest

Interest is calculated from the day following the due date until the day the outstanding amount is paid to the Crown.

6.7.2 Interest Paid by the Crown

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 33(4)

The Crown pays interest on the following balances payable to a project operator:

- for post-payout projects, a royalty overpayment that results when the royalty paid by a project operator exceeds the royalty estimate recorded on a GFE—*if* the Crown does not refund the overpayment by the last day of the month following the month in which the GFE was submitted
- a royalty overpayment identified in an end of period statement—*if* the Crown does not refund the overpayment by the last day of the fourth month following the end of the period
  - Periods follow a calendar year. If the Crown does not refund the overpayment by April 30, interest is payable as of May 1.
- a royalty overpayment that results from a Crown audit recalculation
  - Interest on the overpayment is calculated from the day after the last day of the fourth month following the end of a period. That is, interest is payable as of May 1.

Note

The Crown does not pay interest on royalty overpayments unless refunds are not issued within the time limits prescribed by the Regulation. As a result, it is in a project operator's best interest to submit accurate royalty reports and ensure that monthly good faith estimates (for post-payout projects) are as accurate as possible.

Under the provisions of section 33(4) of the Regulation, royalty overpayments may be remitted to the operator by cheque or deducted from amounts owed to the Crown.

6.7.3 The Rate of Interest Charged or Paid

The rate of interest charged or paid is the yearly rate that is 1% higher than the interest rate established by the Alberta Treasury Branch as its prime lending rate for loans payable in Canadian dollars. This interest rate is in effect as of the first day of the month in which it is posted.

6.8 Financial Audits

All financial information submitted regarding an oil sands royalty project is subject to a financial audit conducted by the Department. The audit ensures that claimed expenditures are

- reasonable
- have specific, practical application for the project
- reflect an actual financial transaction that is supported by appropriate documentation

Financial audits must be conducted within four years of the date when information is filed. If an audit is initiated in the fourth year and is not completed, it can be extended into the next calendar year.

Project Records

Oil Sands Royalty Regulation, *1997 (AR 185/97), section 30*

> Oil sands royalty project owners and operators must keep all records and maintain all records related to applications, reports or statements required under the Regulation.

Purchasers of oil sands projects should be aware that, should they take over as operator of a project, they will be responsible for providing access to any financial information requested by the Department, including information relating to any period before they were operator.

7. Advance Rulings

An advance ruling is the Department's statement on how it will interpret the applicable legislation, policies and guidelines with respect to proposed business arrangements or specific allowed costs that relate to oil sands royalty projects. An advance ruling is not for the purpose of issuing "tentative project approvals".

Project owners or operators must submit a written request each time an advance ruling is required.

The issuance of advance rulings is based on full disclosure of all relevant information. Failure to meet this requirement invalidates the ruling.

Once it has issued an advance ruling, the Department complies with the stated terms until such time as the ruling is rescinded. (see 7.4, "Rescinding an Advance Ruling")

The Department will only issue an advance ruling if the business issue or transaction is one that applies to an actual or proposed oil sands royalty project.

Advance rulings regarding research and development costs are called **concept audits.** For details, see 5.6.4, "Concept Audits"

7.1 Requesting an Advance Ruling

Requests for advance rulings must be made by project owners or their designees. They must be submitted in writing and directed to the attention of the Business Unit Leader, Oil Sands Development. (See Appendix J, "Contact Information")

The request must be clearly identified as a "request for advance ruling" and signed by an authorized designee of the project owner.

7.2 Required Information

A request for advance ruling must include the following information:

- a clear statement of the issue for which the ruling is required
  - This might include an explanation of the purpose of a proposed business arrangement or research project, or a description of the costs of a proposed capital asset.
- a comprehensive analysis of the effect of each relevant fact
- detailed references to pertinent legislation, regulations or authorities
- the applicant's interpretation of the pertinent legislation
- contact information

Additional details may be provided, as appropriate.

7.3 Review and Approval

Requests for advance rulings are processed in the order in which they are received. The Department reviews the submitted material, and in some cases, requests additional information or clarification. In most cases, it issues its ruling within 45 days. More time may be needed for the Department to rule on particularly complex issues.

A request for an advance ruling may be withdrawn at any time before the ruling is issued.

7.4 Rescinding an Advance Ruling

The Department may retroactively revoke an advance ruling if

- the applicant has misrepresented or omitted relevant information in describing the issue
- the business arrangement for which advance ruling was sought is substantially different from what actually transpired

The Department may also revoke an advance ruling if

- the law upon which the ruling was based changes
  - In this situation, the ruling will likely be rescinded as of the date of the change in law, unless the law specifies a different date.

The Department may also revoke an advance ruling if

- government policy changes
  - In this situation, the ruling is rescinded as of the date when the applicant is notified.

8. Dispute Resolution and Appeals

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 35

Mines and Minerals Act, sections 38 and 39

In this chapter, the term “project owner” should be read to include the project operator and the authorized representatives of both.

A formal dispute resolution process is available, should project owners and the Department disagree about royalty assessments. Such disagreements typically arise from differences of opinion with regard to the interpretation of the royalty calculation requirements specified in the regulation.

The dispute resolution process employs a staged approach. A royalty-related dispute is first addressed at the operational level. If it is not resolved there, the project owner may appeal by filing an objection to a calculation or recalculation of royalty with the Department. If the appeal process does not resolve the situation, the matter may be referred to a dispute resolution committee whose members will include representatives of industry and government.

8.1 Issues That May Be Appealed

Ministerial Order #

Mines and Minerals Act, sections 38 and 39

Oil sands project owners generally have the right to object to calculations or recalculations of

- the Crown’s royalty share, and
- amounts owing with regard to royalty

as set out in Section 38 and 39 of the Mines and Minerals Act. Matters that are not listed in sections 38 and 39 of the Mines and Minerals Act are not subject to dispute.

Decisions related to project approvals and amendments, prior net cumulative balances, and other matters subject to the discretion of the Minister cannot be appealed.

8.2 Time Limits

Section 38 of the *Mines and Minerals Act* provides the authority for the Department to make the recalculations or additional calculations referred in Section 8.1. (*Section 47* of the Act provides for access to the records for audit purposes.) *Section 38* stipulates that—unless there is evidence of fraud or wilful misrepresentation, in which case a recalculation can be made at any time—Department-initiated recalculations must be made within four years of the end of the calendar year in which the mineral that is the subject of the recalculation was recovered or the amount owing applied. If an audit is initiated in the fourth year, the four-year period is extended by one year.

By the same token, project owners must exercise their right to request a recalculation within four years of the end of the calendar year in which the original assessment was issued. If a written request by a project owner is initiated in the fourth year, the four-year period is extended by one year.

Project owners have 90 days from the time they receive a royalty assessment or audit report in which to initiate an appeal.

Interest and Penalties

> When royalty is recalculated under *Section 38* of the Act, by *section 38(5)* the Department may also make recalculations or additional calculations of interest payable and related penalties.

8.3 The Dispute Resolution Process

The first stage in dispute resolution related to calculations or recalculations under Section 38 is informal discussions between the project owner and the Department. If the dispute cannot be resolved informally, the project owner may appeal by filing an objection to the royalty calculation or recalculation. The appeal process for oil sands project owners is similar to that available to holders of conventional oil and gas leases.

Project owners must pay all disputed royalty amounts assessed by the Department before they file an appeal. If their appeal is successful, the appropriate amount will be refunded.

8.3.1 Requesting an Appeal

To request an appeal, the project owner must submit a written objection to Director of Dispute Resolution, Legal Services. (See Appendix J, "Contact Information")

The objection must be clearly identified as such. It must be signed by an authorized representative of the project owner and include the following information:

- the decision under dispute
- how, when and by whom the decision was communicated to the project owner
  - Appeals typically result from decisions arising from a royalty assessment decision or a Departmental audit.
- a description of the project owner's attempts to resolve the dispute with the Department's operational staff
- the reasons for the objection
- evidence that the amount under dispute has been paid to the Crown

The request for appeal must be submitted within 90 days of the Department's issuance of the disputed royalty assessment decision or audit report.

8.3.2 Review by the Director of Dispute Resolution

When an objection is received, the Director of Dispute Resolution ("the Director") will determine whether or not it is in accordance with the requirements listed above and may accept or reject the objection. He must provide written notice to the applicant whether he has accepted or rejected the objection.

If the Director believes additional information is required for the objection to meet the requirements, the applicant must provide the requested information to the Director within the 90 day period to initiate an appeal.

If the objection is accepted, the Director will proceed to consider the appeal, by investigating the disputed situation and consulting with the Department and the applicant. He may require additional information from either or both of the parties, which the parties shall provide in a timely fashion. This information may include, without limitation, relevant evidence, legislation, regulations, guidelines, and the parties' analysis and positions with respect to the objection.

The Director carries out his review of the appeal by investigating the situation and consulting with both the project owner and the Department's operational staff. Based on this review, he mediates the dispute and proposes a resolution. The Director will propose this resolution within 180 days of the date he received the objection. This timeline may be extended by a further 90 days if both the applicant and the Department agree.

If both the Department and the project owner accept the proposed resolution, the Director issues a written "**statement of resolution**" to both parties to confirm the agreement.

If the resolution is not accepted by both parties, the Director issues a "**statement of no resolution**" to both parties to document the impasse.

A Note on Timing

> In most cases, the Department and the project owner must accept or reject a resolution proposed by the Director within 180 days of the appeal date. If both parties agree, this time frame may be extended by 90 days.

8.3.3 Requests to Establish a Dispute Resolution Committee

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 35

In the event that a resolution proposed by the Director is not accepted by both parties, the project owner may request that the dispute be reviewed by a dispute resolution committee ("a Committee"). Only matters which have been subject to appeal (as described in 8.1 above), and for which a statement of no resolution has been issued by the Director (as described in 8.3.2 above), may be referred to a Committee.

A matter cannot be referred to a Committee unless a statement of no resolution has been issued.

Pursuant to *section 35* of the regulation, a Committee may be established by a Ministerial Order, issued at the request of the Director. The Director will facilitate the establishment of the committee and assist in coordinating its operations.

A request to establish a Committee must be made to the Director (at the address listed in 8.3.1, above) in writing, by an authorized representative of the project owner, and be received within 90 days of the issuance of a statement of no resolution. The request must include the statement of no resolution, a statement of the dispute the applicant wishes the Committee to review, and the reasons for requesting a review by Committee.

The Director will determine whether the request for review by Committee meets the requirements listed above, and may accept or reject the request. He will provide written notice of his acceptance or rejection to the applicant. If the Director finds the request for review to be incomplete, he may request and accept from the applicant any additional information required. This information must be provided within the 90 day period allowed to request the establishment of a Committee after the issuance of the statement of no resolution.

Where a project owner has requested that a matter go to a Committee, the Minister will not make a decision on the issue in dispute until he has received and considered the recommendations of the Committee.

8.3.3.1 Selecting a Committee

If the request is accepted, the Director will require the Department and the applicant to each identify three individuals who have consented to participate as members of the Committee. The individuals identified cannot be employees of the Department or the applicant, or an affiliate of the applicant. The Department and applicant must also inform the Director of their preferred number of Committee members. This information must be provided within 30 days of the acceptance of the request.

The Director will provide this information to the Minister, and may make recommendations to the Minister on the size and composition of the Committee.

The Minister will determine the size and composition of the Committee. He may choose the members from those names submitted by the Department and applicant, or request that the parties identify additional candidates for consideration. The Minister will establish the Committee within 90 days of the receipt of the information from the Director, unless he determines additional time is required. The Committee will be appointed in accordance with *section 7* of the *Government Organization Act.* Committee members may receive honoraria as determined by the Minister and may be required to take an oath of confidentiality.

Note

> A new dispute resolution committee will be appointed for each royalty dispute hearing.

8.3.3.2 The Role of the Committee

The function of the Committee is to hear the merits of the request, and to provide the Minister with written recommendations, and the reasons for those recommendations, for his consideration.

The Committee may carry out research and conduct such hearings as necessary to carry out its function. The Ministerial Order establishing a Committee may set out the processes to be followed by the Committee – i.e. whether hearings will be oral or written, and whether the Committee may retain outside experts, etc.

Once the Committee concludes its work, it will prepare a written recommendation for the Minister’s review. The recommendation must be supported by the committee’s reasons for its proposal and any supporting documentation the Minister may request. The recommendations must be provided to the Minister within 120 days of the Committee’s appointment, unless the Minister agrees to an extension.

8.3.3.3 The Minister’s Decision

On receiving the Committee’s report, the Minister will review and consider its recommendations and make a decision with regard to the matter in dispute.

8.3.3.4 Notification and Publication

Once the Minister has considered the Committee's recommendations and has made his decision on the matter in dispute, the Director will notify the Department and the project owner of the Minister's decision. Both parties will then cooperate to implement the Minister's decision.

If a Ministerial decision based on the recommendation of a Committee affects the interpretation of an oil sands regulation or guideline, which may affect other oil sands project owners, the Department will inform all interested stakeholders via an Information Letter or some other appropriate method.

8.3.3.5 Costs

Costs associated with or incurred by a Committee will be shared equally by the project owner and the Department.

Committee costs may include honoraria for members.

Committee costs associated with dispute resolution are <u>not</u> an allowed cost of an oil sands royalty project.

8.4 Informal Mediation

The Director may also perform an informal review and mediation of a Project's Prior Net Cumulative Balance (PNCB) and pre-payout costs upon the request of the project owner.

Requests for this service should be addressed, in writing, to the Director within 90 days of the receipt of the decision or audit report of which review is sought. The process outlined in section 8.3.1 for requesting an appeal should be followed, and the project owner must pay all disputed royalty amounts assessed by the Department before they file a request for an informal review.

This process is an informal attempt to resolve an issue between a project operator and the Department and will not involve a Committee or result in recommendations to the Minister. If the matter relates to an issue of the Crown's royalty share or a calculation or recalculation of royalty, it can still be disputed through the process outlined in section 8.3, "The Dispute Resolution Process".

9. General Non-Arm's Length Rules

> The following rules and definitions apply in the interpretation of the 1997 *Oil Sands Royalty Regulation*, *1997* (AR 185/97). They may or may not be applicable in other situations.

The ***Income Tax Regulations*** are governed by the *Income Tax Act* (Canada).

9.1 Non-Arm's Length Transactions

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 2

The capital assets, goods and services required to operate an approved oil sands project may or may not be part of the project, as defined in the approved project description. An asset, good or service that is not part of the project may be provided by an independent third party or by an affiliate. If an affiliate is involved, the use of the asset, good or service is considered to be a non-arm's length transaction, which must be valued in accordance with approved non-arm's length business rules.

The business rules for non-arm's length transactions specify the amount that can be charged to a project. The purpose of these rules is to ensure that the transaction is valued in a manner that does not direct payable royalty away from the Crown. The flowchart in Figure 12 shows how the rules are applied.

For royalty purposes, all non-arm's length transactions for basic services associated with oil sands project operations are treated as if they are part of the project, regardless of whether they are part of the project description.

9.1.1 Affiliates

Oil Sands Royalty Regulation, *1997* (AR 185/97), section 2

A company is considered affiliated with another company if the criteria outlined in subsection 1206(5) of the *Income Tax Regulations* apply. However, in making this determination, paragraph 1206(5)(a) shall be read as if it were replaced by the following:

- a person and another person (in this paragraph, referred to as "that other person") are connected with each other if

  (i) the person and that other person are not dealing at arm's length

  (ii) the person has an equity percentage in that other person that is not less than 10%, or

  (iii) where the person is a corporation, the corporation and that other person are linked by another person who has an equity percentage in each of them of not less than 10%.

Persons are not dealing at arm's length with each other if they would not be considered to be dealing at arm's length under the *Income Tax Act* (Canada).

Person Defined

> As defined in section 1(v) of the Regulation, the term "person" includes firms, trusts, partnerships, joint ventures, associations, governments or government agencies.

9.1.2 Capital Assets

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 7.4

Assets are considered capital assets if they

- Are used to provide goods and services, rented to third parties, required for administrative purposes, or used for the development, construction, maintenance or repair of other capital assets
- Were acquired, constructed or developed for ongoing use, and
- Are not intended for sale in the ordinary course of business

Capital assets are valued when the asset is delivered to the project site at the lesser of

- The amount charged to the project
- Fair market value (as defined in section 9.1.4), when a reasonable determination can be made, or
- The asset's net book value

9.1.3 Net Book Value

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 9

The net book value used to determine allowed or non-allowed costs is the remaining undepreciated amount of a capital asset – as recorded in the financial records (consistent with GAAP) of the project owner, operator or other person who provided the asset. In other words, net book value is the original cost less accumulated depreciation.

If a capital asset has been claimed under another royalty regime – such as the *Enhanced Recovery of Oil Royalty Reduction Regulation* or the *Natural Gas Royalty Regulation, 2004* – the Department's records are used to assign net book value.

Capital assets for oil sands royalty projects are depreciated at a rate of 5% per year over twenty years using a straight-line depreciation (in accordance with the Minister's direction given under *section 7.1(2)(c(i).*)

9.1.4 Fair Market Value

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 7.3 and 9

Fair market value is determined based on comparable, open-market transactions among unaffiliated parties. Determinations of fair market value are made by the Minister. The Minister's assessment of what constitutes a comparable open market is made on a case-by-case basis.

Where the Minister is satisfied that a fair market value can be determined, for goods or services other than transportation on pipelines, the Minister may, without limiting any other method of determination, adopt

- the published price of comparable goods or services, if that price is generally adopted by buyers and sellers
- for comparable goods or services, a price that is prescribed in other regulations associated with the *Mines and Minerals Act*
- the average price paid for comparable goods or services during transactions by unaffiliated buyers and sellers

The prices used to determine fair market value may be adjusted to reflect transportation or delivery costs.

Specific cost rules apply in determining fair market value for pipeline services. Refer to Chapter 5 for details.

9.2 Cost Rules Associated with Non-Arm's-Length Transactions

Oil Sands Royalty Regulation, *1997* (AR 185/97), sections 7.1 to 7.4

9.2.1 Goods and Services

Oil Sands Royalty Regulation, *1997 (AR 185/97), sections 7.2 and 7.3*

Different cost rules apply to different types of non-arm's length goods and services supplied to a project. The appropriate rule is determined by three factors:

1. whether or not a fair market value can be established

2. whether or not a capital asset was used
   - When a capital asset is used, cost-of-service calculation rules apply.

3. in the case of a service, whether or not the service is considered "**basic**"
   - The classification of a service as "basic" or "non-basic" determines how allowed costs are determined.

9.2.2 Basic Services

Oil Sands Royalty Regulation, *1997 (AR 185/97), sections 7.1(2)(b) and 7.2(2)(b)*

A basic service is any service provided to a project from a non-project non-arm's length capital asset that is required to produce the project's product. As a minimum, the project's product is the first marketable oil sands product: cleaned crude bitumen. Projects may also be defined as producing something more than cleaned crude bitumen.

Basic services include, but are not limited to, services provided through the use of such capital assets as

- wells
- gathering lines
- production and separation facilities
- cleaning facilities
- on-site power transmission and distribution lines, and
- steam generation facilities (including the steam-generating portion of co-generation plants)

Basic services do not include electricity (provided from a co-generation plant), which is defined as a good under the Regulation, or natural gas, which is also considered a good.

Basic services are charged to the project at the lesser of:

- The amount charged to the project by the project owner(s) or affiliate(s); or
- The cost of service, as explained below.

The cost of service calculation provides for a rate of return on capital based on the long-term bond rate, and a depreciation based on the 5% annual straight-line method, in accordance with *section 7.1(2)(c)(i)*.

The Joint Industry Task Force Report on Processing Fees (JP-95) was used as a general guide for the cost of service calculation, but is not binding in determining the cost of service for a facility. The calculation does not include a minimum capital rate base (i.e., 50%) as suggested by the JP-95.

The rate of return and depreciation are allocated based on the capacity of the capital asset. Operating costs for the capital asset are allocated based on annual throughput.

9.2.3 Goods and Non-Basic Services

Oil Sands Royalty Regulation, *1997 (AR 185/97), section 7.2(1)*

The costs allowed in respect of goods and non-basic services depends on whether a fair market value can reasonably be determined for those goods or non-basic services, and whether the goods or non-basic services are provided using a non-project capital asset.

9.2.3.1 Fair Market Value for Goods and Non-Basic Services Can Be Determined

For goods and non-basic services that do not use a non-project capital asset, the allowed costs of the goods or non-basic services are the lesser of

- the amount charged to the project; or
- fair market value

9.2.3.2 Fair Market Value for Goods and Non-Basic Services Cannot Be Determined

For goods and non-basic services that do not use a non-project capital asset, the allowed costs of the goods or services are the lesser of:

- the amount charged to the project; or
- the actual cost incurred by the project owner, operator, or an affiliate of either (or the person from whom the good or service was obtained), to produce the good or perform the service.

9.2.4 Non-Basic Services Using Non-Project Capital Assets

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 7.2(3)

The costs allowed in respect of non-basic service provided by a non-project capital asset will depend on whether a fair market value can reasonably be determined for those non-basic services.

Note

> Special rules for non-basic pipelines are in section 9.2.6. Rules for co-generation plants may be found in Chapter 5.

9.2.4.1 Fair Market Value for Non-Basic Service from a Non-Project Capital Asset Can Be Determined

Where fair market value can reasonably be determined for a non-basic service provided by a non-project capital asset, the cost of the service will be the lesser of

- the amount charged to the project; or
- fair market value

9.2.4.2 Fair Market Value for Non-Basic Service from a Non-Project Capital Asset Cannot Be Determined

Where fair market value cannot reasonably be determined for a non-basic service provided by a non-project capital asset, the cost of the service will be the lesser of

- the amount charged to the project; or
- the cost of service

The cost-of-service calculation provides for a rate of return on capital based on the long-term bond rate plus a premium to reflect the risk of operating the capital asset. The Minister will periodically assess the risk premium and adjust it as required.

The cost of service calculation provides for depreciation based on the annual straight-line method, with the depreciation rate determined by the Minister.

JP-95 can be used as a general guide, but it is not binding in determining the cost of service for a capital asset. There will be no minimum capital rate base (i.e. 50%), as suggested by the JP-95.

The rate of return and depreciation are allocated based on the capacity of the capital asset. Operating costs for the capital asset are allocated based on annual throughput.

9.2.5 Non-Basic Service Using a Project Capital Asset (Custom Processing)

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 7.2(3)

Where a project provides non-arm's length custom processing to other projects, the net book value of the project capital asset will be used in determining the custom-processing fee.

Where a project provides custom processing to an arm's length operator a fair market value must be charged for the service. The fair market value of the transaction is based on either relative transactions within the region or from an estimate of the project capital asset's value. The latter method would apply only if the company's statements assigned zero or minimal net book value to the project capital asset.

9.2.6 Non-Basic Pipelines

9.2.6.1 Fair Market Value for Transportation Can Be Determined

Where a non-basic pipeline transports oil sands products from a project, and a fair market value can be determined for the transportation service, the pipeline charge allowed as a unit price deduction for the project will be the lesser of:

- the amount charged to the project; or
- fair market value

In determining fair market value of the transportation service, the Minister may adopt one of the following three methods:

(1) A regulated tariff charged for the service.

(2) A tariff charged by the owner of the pipeline, if:

- the conditions under 1 do not apply.
- the pipeline is subject to a complaint-based regulation,
- the tariff is generally agreed to and paid by unaffiliated shippers who obtain the service,
- the pipeline has published tariffs,
- the tariffs and other terms of obtaining service do not unjustly discriminate among shippers seeking service, and
- the tariff is just and reasonable under the circumstances, or

(3) A tariff of either (a) the weighted average of prices paid by unaffiliated shippers for comparable service, or (b) if there is no comparable service, the weighted average of prices for all unaffiliated service on a pipeline, if:

- the conditions under 1 and 2 do not apply,
- the pipeline is subject to a complaint-based regulation,
- not less than 2/3 of the volume of oil sands product shipped on the pipeline is owned by shippers unaffiliated with the pipeline owner, and
- the weighted average price is just and reasonable under the circumstances.

Note

> A pipeline is subject to regulation on a complaints basis if a customer or potential customer of the pipeline can, by complaint to a regulatory authority, have the pipeline terms of service and the charges for service reviewed and fixed.

9.2.6.2 Fair Market Value for Transportation Cannot Be Determined

Where a non-basic pipeline transports oil sands products from a project, and a fair market value cannot be determined for the transportation service, the pipeline charge allowed as a unit price deduction for the project will be the lesser of:

- the amount charged to the project; or
- the cost of service

9.2.6.3 Cost of Service Calculation Methodology For Non-Basic Pipelines

The annual depreciation charge, capital return, and operating costs for the non-basic pipeline will be allocated based on annual throughput.

The pipeline's allowed capital costs will be depreciated on a straight-line basis over its useful life, which for royalty calculation purposes is estimated to be not less than 20 years (5% straight-line depreciation). There will be no floor on the undepreciated capital balance to determine the return on capital.

The allowed rate of return on capital (RORC) will be calculated using a pre-tax weighted average cost of capital formula, which is:

$$\text{RORC} = \left(\begin{array}{l}\text{Deemed Debt}\\\text{Percentage}\end{array}\right)\left(\begin{array}{l}\text{Deemed Cost}\\\text{of Debt}\end{array}\right) + \left(\begin{array}{l}\text{Deemed Equity}\\\text{Percentage}\end{array}\right)\frac{\text{Deemed Cost of Equity}}{\text{(1-Deemed Corporate Income Tax Rate)}}$$

The parameters used in the previous formula are as follows:

- Deemed debt percentage = 45%,
- Deemed equity percentage = 55%,
- Deemed cost of debt = LTBR plus 1%, and
- Deemed cost of equity = the multi-pipeline rate, as published by the National Energy Board on an annual basis.

Other parameters (capital structure and corporate tax rate) will be revisited at the Department's discretion, or when there are significant market or tax changes.

Note that the RORC is calculated as a pre-tax weighted average cost of capital formula with corporate income taxes payable accounted for within the formula. Accordingly, taxes will not be included in the pipeline's revenue requirement.

Note

The Minister may, at his discretion, periodically revisit any cost of service calculation, whether used in determining the allowed cost for a project or a deduction from unit price.

9.3 Revenue Rules Associated with Non-Arm's-Length Transactions

Oil Sands Royalty Regulation, 1997 (AR 185/97), sections 8 and 9

When any consideration is received for a non-arm's-length transaction, the value of that consideration is the greater of

- Fair market value, or
- The value agreed to by the parties involved in the transaction.

If some or all of the consideration is non-monetary, its value is the sum of the money portion plus the value of the non-money portion.

What is consideration?

Consideration is a legal term that means something of value, such as money or services, given by one party to another in exchange for goods received or services rendered.

Figure 11 Cost rules for non-arm's-length assets