2010 OIL SANDS
PERFORMANCE REPORT
The companies in which Royal Dutch Shell plc directly and indirectly owns investments are separate entities. In this report "Shell", "Shell group" and "Royal Dutch Shell" are sometimes used for convenience where references are made to Royal Dutch Shell plc and its subsidiaries in general. Likewise, the words "we", "us" and "our" are also used to refer to subsidiaries in general or to those who work for them. These expressions are also used where no useful purpose is served by identifying the particular company or companies. "Subsidiaries", "Shell subsidiaries" and "Shell companies" as used in this report refer to companies in which Royal Dutch Shell either directly or indirectly has control, by having either a majority of the voting rights or the right to exercise a controlling influence. The companies in which Shell has significant influence but not control are referred to as "associated companies" or "associates" and companies in which Shell has joint control are referred to as "jointly controlled entities". In this report, associates and jointly controlled entities are also referred to as "equity-accounted investments". The term "Shell interest" is used for convenience to indicate the direct and/or indirect (for example, through our 24% shareholding in Woodside Petroleum Ltd.) ownership interest held by Shell in a venture, partnership or company, after exclusion of all third-party interest.

This report contains forward-looking statements concerning the financial condition, results of operations and businesses of Royal Dutch Shell. All statements other than statements of historical fact are, or may be deemed to be, forward-looking statements. Forward-looking statements are statements of future expectations that are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in these statements. Forward-looking statements include, among other things, statements concerning the potential exposure of Royal Dutch Shell to market risks and statements expressing management's expectations, beliefs, estimates, forecasts, projections and assumptions. These forward-looking statements are identified by their use of terms and phrases such as "anticipate", "believe", "could", "estimate", "expect", "intend", "may", "plan", "objectives", "outlook", "probably", "project", "will", "seek", "target", "risks", "goals", "should" and similar terms and phrases. There are a number of factors that could affect the future operations of Royal Dutch Shell and could cause those results to differ materially from those expressed in the forward-looking statements included in this report, including (without limitation): (a) price fluctuations in crude oil and natural gas; (b) changes in demand for the Shell’s products; (c) currency fluctuations; (d) drilling and production results; (e) reserve estimates; (f) loss of market share and industry competition; (g) environmental and physical risks; (h) risks associated with the identification of suitable potential acquisition properties and targets, and successful negotiation and completion of such transactions; (i) the risk of doing business in developing countries and countries subject to international sanctions; (j) legislative, fiscal and regulatory developments including regulatory measures addressing climate change; (k) economic and financial market conditions in various countries and regions; (l) political risks, including the risks of expropriation and renegotiation of the terms of contracts with governmental entities, delays or advancements in the approval of projects and delays in the reimbursement for shared costs; and (m) changes in trading conditions. All forward-looking statements contained in this report are expressly qualified in their entirety by the cautionary statements contained or referred to in this section. Readers should not place undue reliance on forward-looking statements. Additional factors that may affect future results are contained in Royal Dutch Shell’s 20F for the year ended December 31, 2010 (available at www.shell.com/investor and www.sec.gov). These factors also should be considered by the reader. Each forward-looking statement speaks only as of the date of this report, April 14, 2011. Neither Royal Dutch Shell nor any of its subsidiaries undertake any obligation to publicly update or revise any forward-looking statement as a result of new information, future events or other information. In light of these risks, results could differ materially from those stated, implied or inferred from the forward-looking statements contained in this report.

We may have used certain terms in this report that SEC’s guidelines strictly prohibit us from including in filings with the SEC such as recoverable bitumen. U.S. Investors are urged to consider closely the disclosure in our Form 20F, File No. 1-32575, available on the SEC website www.sec.gov. You can also obtain these forms from the SEC by calling 1-800-SEC-0330.
ABOUT THIS REPORT

This report to our stakeholders is an important part of Shell’s continuing dialogue with governments, industry, environmental groups, community stakeholders, Aboriginal Peoples and the public about our oil sands operations.

SCOPE

In this report we provide discussion on our performance in five key areas: CO₂, water, tailings, land and reclamation, and people, communities and engagement. The scope of this 2010 report has expanded over that for 2009 to include performance data for Shell’s mineable and in situ oil sands operations in production as well as upgrading in Canada. This 2010 report also includes performance data for the Jackpine Mine (JPM), which came onstream in late August, 2010. Data presented for the JPM accounts for the whole of 2010 capturing both construction activities leading to startup and its four months of production.

As this is an expansion of scope over last year’s report, which only covered the Muskeg River Mine (MRM) and Scotford Upgrader, certain data sets will differ, particularly because in situ oil sands extraction processes differ from those used in mining. Historical data presented prior to 2010 has been retroactively updated to incorporate in situ performance where applicable.

A regulatory application for an 80,000 barrel-per-day expansion of Shell’s in situ Peace River operations submitted in January, 2010, is not included in the scope of this report because it is not operational. The expansion portion of the Scotford Upgrader (60% Shell share), which was under construction in 2010 is also not in scope.

Unless otherwise stated, all data presented for the MRM, JPM and Scotford Upgrader is in reference to total Athabasca Oil Sands Project (ACOSP) performance before division amongst the joint venture partners. Data presented for in situ operations is 100% Shell share.

All monetary amounts referenced in this document are in Canadian dollars unless otherwise noted.

IN SCOPE:
- Muskeg River and Jackpine Mines
- Scotford Upgrader (base operations)
- In situ: Peace River, Orion, Seal, Cliffdale, Chipmunk

OUT OF SCOPE:
- Scotford Upgrader Expansion
- Proposed Peace River Expansion
- Proposed Jackpine Mine Expansion
- Proposed Pierre River Mine
- Grosmont
Global energy demand is growing at an accelerated rate. All energy sources will be needed to meet this demand and the oil sands are an important resource in a world with increasing energy needs.

Shell operates in all of Alberta’s oil sands areas – Athabasca, Cold Lake and Peace River – with billions of barrels of recoverable bitumen. The term oil sands, when used in this report, refers to all of Shell’s mining, upgrading and in-situ operations.

Oil sands are a mixture of water, sand, clay and bitumen, a heavy hydrocarbon. Bitumen deposits located near the earth’s surface are recovered through open pit mining using large shovels and trucks.

Where deposits are too deep to mine, they may be recovered in situ (in place) using conventional drilling techniques. Shell employs two methods to extract bitumen in situ: thermal recovery and cold production. Thermal recovery techniques include injecting steam underground to heat the bitumen to allow it to flow. It is then pumped to the surface, leaving the sand and clay in place. Where the bitumen is more mobile, cold production involves pumping product to the surface via long horizontal or vertical wells without the need for heat.

Once the bitumen is separated from the oil sands, it is either converted into synthetic crude at an upgrader or sold to refineries with upgrading capability to produce gasoline, diesel fuel and other consumer products.

**Athabasca Oil Sands Project (AOSP)**

The AOSP is a joint venture between Shell (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). The AOSP includes the MRM and JPM open...
pit bitumen mining operations located north of Fort McMurray, Alberta and the Scotford Upgrader, located near Fort Saskatchewan, Alberta, which upgrades bitumen into synthetic crude oil. Shell operates the mines and upgrader on behalf of the AOSP joint venture.

The MRM currently has mining production capacity of 155,000 barrels per day (bpd) and the JPM a capacity of approximately 100,000 bpd. The Scotford Upgrader has an average upgrading capacity of 155,000 bpd. The Scotford Upgrader expansion is scheduled to startup in 2011 and will increase capacity to 255,000 bpd.

In Situ Operations
Shell extracts bitumen through both thermal and cold production techniques in the Peace River oil sands area of northern Alberta. The Peace River Complex (PRC) produces bitumen using thermal and cold recovery methods. Shell’s other cold production facilities include the Seal Battery and Clifftdale Battery and production from the Chipmunk field. Shell’s Onion project, which came onstream in 2007 is a Steam Assisted Gravity Drainage (SAGD) thermal project in the Cold Lake oil sands area. Shell processed around 21,000 bpd in 2010 from its in situ operations, with roughly half from cold production.
Carbon dioxide (CO₂) emissions from Canada’s oil sands account for 0.1 per cent of global greenhouse gas (GHG) emissions and about five per cent of Canada’s total GHG emissions [source: 2010 Natural Resources Canada]. The oil sands are, however, the fastest growing source of GHG emissions in Canada, challenging industry to continue innovating to reduce emissions.

Shell was one of the first energy companies to acknowledge the challenge of climate change and has consistently taken a proactive stance towards CO₂ emissions management.

Total Emissions
As displayed in the chart on the following page, Shell’s oil sands operations (mining, upgrading and in situ) generated a combined total of 5.0 million tonnes (Mt) of CO₂ equivalent (CO₂e) in 2010. This figure includes both direct and indirect emissions. Direct emissions come from sources owned by the facilities such as onsite transportation, and fugitives from tailings pond and mine face emissions. Indirect emissions come from sources that are not owned by Shell such as external power generation.

Total emissions increased from 4.7 Mt CO₂e in 2009 to 5.0 Mt CO₂e in 2010 with the startup of the JPM. Direct emissions, while offset by lower production due to a two month maintenance turnaround, were higher in 2010 as a result of JPM coming onstream. Overall emissions also increased due to a variety of factors, including an increase in diesel consumption at the MRM to accommodate longer truck travel distances that are required as the mine increases in size. Trend data on total CO₂e emissions shows an overall increase in the 2006-2010 period.

CO₂ Intensity
Intensity-based reporting of CO₂e emissions reflects emissions on a per barrel produced basis. Shell produced around 53 million barrels (bbls) from its mining and in situ operations in 2010. CO₂e emissions intensity increased from 82.8 kg/bbl in 2009 to 88.5 kg/bbl in 2010, which is largely attributed to reduced production during the maintenance turnaround referenced earlier as well as the startup of JPM. This resulted in proportionately more CO₂e emissions from increased energy use while production levels were lower. The intensity graph on the following page charts our overall CO₂e emissions intensity including internal energy efficiency measures as well as showing the impact of externally purchased offsets. The line charting total CO₂e intensity including offsets is intended to show the efforts we are making to offset the impact of emissions from our operations and does not suggest a physical reduction in overall emissions or emissions intensity.

Alberta’s Specified Gas Emitters Regulation (SGER)
Under the SGER (which came into effect in 2007), the MRM, JPM and Scotford Upgrader are required to achieve a two per cent reduction per year in their direct emissions intensity over the 2006 baseline until a 12 per cent target is reached. Peace River’s thermal operations are required to achieve an emissions intensity which is 12 per cent lower than its 2006 baseline. The regulators target direct emissions as these are under the operational control of each facility. Orion is a relatively new facility that is required to comply with SGER in 2011. Our cold production in situ sites are not subject to the regulation as they produce less than the 100,000 tonnes of CO₂e per year threshold.

Under the SGER, compliance can be achieved in four ways: through implementing energy efficiency projects; purchasing certified emissions offsets from Alberta based projects; through emission performance credits generated at facilities operating below their regulatory target; and through contributions to the Climate Change and Emissions Management Fund (CCEMF) at $1.5 for each tonne for volumes over the allowable limit.
In 2010, the MRM, JPM, Scotford Upgrader and PRC’s thermal operations met their regulated intensity target through energy efficiency projects and the retirement of Alberta based offsets equivalent to nearly 550,000 tonnes of CO₂e. Shell also generated approximately 615,000 tonnes of CO₂e credits through the use of cogeneration. The balance of our compliance was achieved through contributions to the CCEMF.

**Cliffdale Gas Gathering System**

When Shell acquired the Cliffdale cold production facility, casing vent gas (CVG) was coproduced with bitumen and a portion of the CVG was consumed as fuel for tank heaters and engines driving the down-hole production pumps. However, excess CVG was also vented or flared. Shell took action to improve this situation in line with our own standards on venting and flaring. This led to the construction of a gas gathering system and pipeline from the Cliffdale production pads to our PRC, which was completed in 2010. The system collects and compresses CVG before shipping it via pipeline to the PRC where it displaces approximately 180,000 cubic metres of purchased fuel gas. Conservation of this gas significantly reduces emissions by approximately 500,000 tonnes of CO₂e as compared to previous years.

**Heavy Oil CO₂ Strategy**

Shell’s Heavy Oil CO₂ Strategy details plans to address emissions at our oil sands operations through investment in developing a range of CO₂ reduction measures over the next five years in the following key areas:

- **Energy Efficiency**

  Energy efficiency projects are the preferred option as they reduce CO₂ emissions and operating costs. We analyzed a wide range of options and decided to take action in a number of areas while others will require more analysis. For example, by reducing the amount of time between workers’ shift changes at the MRM, we reduced process idling time and achieved reductions of approximately 30,000 tonnes of CO₂e per year. An investigation into energy efficiency options between existing and expansion facilities identified opportunities that could yield large energy savings in the future. Furthermore, Shell continues to research new technologies that could improve our energy efficiency.

- **Alternative Fuels and Lower Carbon Energy Sources**

  We are determining the feasibility of running haul trucks on electricity, liquified natural gas and biodiesel. In September, 2010 we began piloting a new diesel blend in some of our large MRM mine trucks which could help to improve fuel efficiency.

**Carbon Capture and Storage (CCS)**

Shell’s Quest CCS project plans to capture more than one million tonnes per year of CO₂e from the Scotford Upgrader and transport it by pipeline to a location north of the upgrader where it would be injected and stored more than two kms underground. Shell submitted regulatory applications to the Canadian Environmental Assessment Agency, Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment in November 2010. Moving ahead will depend on factors including the outcome of applications, economic feasibility and community consultation. Pending regulatory approval, Shell plans to make a final investment decision in 2012 to begin construction, with CO₂ injection beginning in 2015 – making it the first CCS project associated with oil sands in Canada.

**Offsets**

Shell purchases carbon emission offsets from Alberta based projects in compliance with the SGER. In 2010, offsets were purchased from wind, biomass and reduced/no soil tillage projects. Under the SGER, cogeneration facilities, such as the ones at MRM and the Scotford Upgrader, also generate emission performance credits from their steam and power generation since this technology is less CO₂ intensive than having steam and power requirements met through individual sources. Shell also purchases carbon emission offsets outside of Alberta from tree planting and peatland conservation programs.
The AOSP has mining operations on the Athabasca River and upgrading operations on the North Saskatchewan River. Oil sands mining requires water to separate bitumen from the sand. The Scotford Upgrader draws water largely for hydrogen production and equipment cooling. Shell’s PRC withdraws water from the Peace River to generate steam for bitumen extraction. Water needs at Orion and our other in situ operations are largely met by using non-potable water.

**Water Use at the AOSP**

In 2010, about 75 per cent of the MRM and JPM’s water needs were met using water reused from our tailings ponds with the remainder through withdrawals from the Athabasca River (19%) and other freshwater sources — surface runoff and groundwater (7%). Average water intensity at the two mines was 2.4 barrels of freshwater (from the Athabasca River) for every barrel of bitumen produced. This is a significant increase over freshwater intensity reported in 2009 and is attributed to the JPM’s heightened need to withdraw water to support startup of operations during a year of reduced production resulting from the turnaround. Water recycling was also lower due to JPM’s lack of recycle water available at startup. As recycle water accumulates, freshwater use per barrel of bitumen at JPM will decline.

Shell’s mining operations have permits to use 0.6 per cent of the Athabasca River’s mean annual flow and used less than 0.1 per cent of our allotment in 2010. No process water is directly released to the environment by MRM or JPM. In 2010, the Scotford Upgrader used 0.46 barrels of fresh water for every barrel of bitumen produced. Approximately 60 per cent of fresh water taken from the North Saskatchewan River in 2010 was consumed in the upgrading process, largely due to water evaporation in the cooling tower. Process affected water was treated at our wastewater treatment plant and reused in the cooling tower, while all other water was tested and returned to the river as effluent. The Scotford Upgrader has permits to use 0.1 per cent of the North Saskatchewan River’s mean annual flow and diverted 0.08 per cent in 2010.

**In Situ Water Use**

Total freshwater consumption for our in situ operations was 1.9 million m³ in 2010. This equated to about 1.6 barrels of fresh water for every barrel of bitumen produced. Our current water withdrawal license for the PRC represents less than 0.007 per cent of the river’s average annual flow, and we currently use about half of this amount.

To limit freshwater consumption, Shell’s Orion SAGD project recycled approximately 90 per cent of water in 2010, in addition to using non-potable sources as makeup water.
WATER MONITORING

Shell monitors all diversions from the Athabasca River, releases from all settlement ponds and all water recycled from the external tailings facility. Regional water quality monitoring is conducted by the Regional Aquatics Monitoring Program (RAMP), Alberta Environment, industry and other organizations. Concerns were raised in 2010 about the effectiveness of RAMP monitoring through a scientific peer review. Shell supports the resulting work led by Alberta Environment and Environment Canada to develop a world-class and transparent monitoring program.

A cooperative monitoring program with Alberta Environment was implemented on the Muskeg River upstream and downstream of our mines in 2008. This increased sampling frequency from quarterly to monthly. Where technology is available, some parameters are now monitored continuously with automated systems and passive samplers.

In addition to documenting performance, this ensures any issues can be more quickly detected and addressed. Shell’s monitoring program is continually evolving and expanding to adapt as our knowledge of the ecosystem and technology improves.

Groundwater monitoring is conducted to establish baseline groundwater conditions, evaluate potential changes in water quality and to ensure there are no releases of process water to the surrounding environment. Active groundwater wells (71 at MRM and 42 at JPM) are sampled two to four times per year using accepted sampling protocols.

The University of Waterloo investigated Shell’s MRM tailings facility and reported that the seepage collection system is working to effectively contain process-affected water (NRC Research Press, www.cij.nrc.ca, November 2010).

Phase 2 Water Management Framework

Shell actively participated in the creation of and supports the Phase 2 Water Management Framework recommendations. Accordingly, we will reduce our water intake from the Athabasca River to 0.2 cubic metres per second when the river’s flow rate is low (87 cubic metres per second or below) along with other reductions during less extreme low flow periods. Reducing water use during winter low flow periods is particularly important as there is greater risk to the aquatic ecosystem. We expect to achieve this reduction through a combination of measures such as on-site water storage for use during low flow periods, use of groundwater and increased water efficiency.

An independent Royal Society of Canada review published in 2010 noted that cumulative industry withdrawals do not threaten the viability of the Athabasca River system if the Framework recommendation is fully implemented and enforced.
After oil sands ore is excavated, warm water is added to separate bitumen from the sand and clay. The remaining water and solids are referred to as tailings, which consist of water, coarse sand, silt, clay particles and small amounts of bitumen. These are initially stored in an above ground area called an external tailings facility (ETF). Once mining is sufficiently advanced, tailings can be deposited in the mine pit. In-pit storage reduces the surface disturbance footprint of our operations and allows for faster reclamation of mined areas. Shell started using in-pit storage at MRM in mid-2010.

Tailings facilities serve important settling, water storage and water reuse purposes. Solids settle out of the tailings enabling water to be recovered for reuse in the bitumen extraction process. Recovered solids are used for construction purposes and for future reclamation.

Shell’s tailings management planning addresses issues such as recovery of water from tailings, systems to manage and monitor seepage, wildlife deterrent systems and progressive reclamation activity.

In situ oil sands development does not produce tailings.

**Directive 074**

In 2009, the ERCB, issued a new tailings directive, designed to reduce the amount of fluid fine tailings and advance the timing of reclamation.

Shell’s Tailings Management Plans for the MRM and JPM were approved with conditions by the ERCB in 2010. Our greatest challenges are increasing fines capture and advancing technology, development and ongoing internal design work to gain sufficient dried tailings strength within an appropriate timeframe. The conditions can be viewed in the ERCB’s news releases dated Sep 20, 2010 and Dec 17, 2010. Visit www.ercb.ca and search under the organization’s “media room”.

**Bird Deterrent System**

Shell’s radar-based bird deterrent system (Bird-Avert) continues to control avian mortality rates. When a bird is detected by a radar system to be flying in the vicinity of a tailings pond, the system activates a number of devices including noise deterrents, strobe lights and an oversized mechanical peregrine falcon.

Recorded avian mortalities at MRM decreased from 18 in 2009 to 10 in 2010. The JPM reported 23 avian mortalities in 2010. Avian mortalities at our mines were attributed to contact with bitumen or tailings or from collisions with vehicles or buildings.
Tailings Monitoring

Tailings water contains concentrated naturally occurring substances that are toxic, so we continually monitor, assess and manage them to protect water and wildlife. An ETF is constructed from compacted coarse sands that, over time, drains small amounts of tailings water. The amount of seepage is small, and Shell has designed and implemented seepage collection systems to protect groundwater. Seepage is captured by drains, redirected to a collection pond and returned to the ETF for reuse. Shell monitors surrounding groundwater to check water quality and ensure this collection system is functioning properly. There are 39 monitoring wells in the MRM and JPM tailings pond seepage monitoring program. This includes six new wells drilled around the ETFs in 2010.

Shell monitors surface water in addition to water sampling done by Alberta Environment and RAMP at locations throughout the Muskeg River watershed. If monitoring results indicate any impact from Shell tailings water on local aquatic areas, Shell will take action to protect water quality.

In October 2010, Shell found additional water in the bottom of a section of its oil sands mine pit at the MRM. The area was being prepared to receive in-pit tailings. The water was confirmed to be saline and from an aquifer below the mine pit and is completely contained within a segregated area at MRM. Our work plan is focused on on-site containment, evaluating options to seal the inflow of water, and assessing options for the saline water.

### Total Volume of Liquid Discharged to External Tailings Facility (million m3)

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>MRM</td>
<td>89.1</td>
<td>102.5</td>
<td>112.4</td>
<td>118.9</td>
<td>82.2</td>
</tr>
<tr>
<td>JPM</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>–</td>
<td>20.7</td>
</tr>
</tbody>
</table>

**Total Volume of Tailings Discharged to External Tailings Facilities**

In August, 2010, the JPM came onstream and began storing tailings in an ETF. Through the addition of this facility, Shell’s external and in-pit tailings facilities now occupy a total area of approximately 24 km² – 14 km² at the MRM and 10 km² at the JPM.

The total volume of liquid discharged to the MRM ETF in 2010 was about 82 million m³. This is a decrease over the 119 million m³ discharged in 2009 due to a scheduled two month maintenance shutdown of the MRM plant site in the second quarter of 2010, as well as other maintenance in the third quarter of 2010.

**Atmospheric Fines Drying**

Since 2006, Shell has invested well over $100 million into tailings research and development and demonstration projects such as Atmospheric Fines Drying (AFD). AFD technology involves collecting fine tailings from the ETF and adding chemical agents to help accelerate de-watering. Treated material is then placed on a sloped surface to enhance further drying through evaporation. Released water is collected and returned to the ETF for reuse. The deposits that remain will ultimately meet ERCB strength requirements and support reclamation objectives.

Located at the MRM, Shell’s AFD test facility occupies approximately 0.3 square kms and will deliver a final deposit of 250,000 tonnes of reclaimed sand and clay by the end of 2011. A second demonstration phase in 2011 will further optimize the process and include an additional 0.45 square kilometers of drying area.

In December, 2010, Shell and several other oil sands companies pledged to share existing tailings research and technology to help accelerate the pace of reclamation using the most advanced environmental methods. Tailings technical information will also be made more broadly available to industry members, academia, regulators and others interested in collaborating on tailings solutions.
A key component of Shell’s mineable oil sands developments is an integrated closure and reclamation plan, which details how disturbed lands will be reclaimed to a land capability equivalent to what it was prior to development. This is a long-term program that is planned before mine disturbance and active throughout operations to the end of project life and into the closure phase.

During the early years of mine operation, most reclamation activity consists of site clearance and timber salvage together with removal and stockpiling of reclamation soils and seeds for later use. As development advances, disturbed areas will be re-contoured, drainage patterns established, reclamation materials returned and revegetation undertaken.

In situ operations have a significantly smaller footprint than those of mining operations because bitumen separation is conducted underground. In situ developments require drilling pads for extraction in addition to processing facilities, connecting pipelines and roads. With mining operations, the disturbance area is larger given the combination of mining, excavated overburden storage and tailings placement. About one cubic metre of waste material is moved to process 1.33 cubic metres of oil sands ore. In accordance with the government-approved Closure, Conservation and Reclamation Plans, mining areas will be progressively reclaimed over the course of operations and through to the closure phase.

**2010 Land Status**

Land use at the end of 2010 for JPM and MRM is described in the following table.

<table>
<thead>
<tr>
<th>Activity</th>
<th>JPM (all units hectares)</th>
<th>MRM (all units hectares)</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPEA approved footprint</td>
<td>7,669</td>
<td>12,572</td>
</tr>
<tr>
<td>Total active footprint</td>
<td>3,541</td>
<td>6,246</td>
</tr>
<tr>
<td>Cleared</td>
<td>828</td>
<td>726</td>
</tr>
<tr>
<td>Disturbed</td>
<td>2,708</td>
<td>5,393</td>
</tr>
<tr>
<td>Permanent Reclamation</td>
<td>0</td>
<td>16</td>
</tr>
<tr>
<td>Temporary Reclamation</td>
<td>6</td>
<td>111</td>
</tr>
<tr>
<td>Certified Reclamation</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

The Scotford Upgrader occupies an area of about 113 hectares (ha). Our in situ operations had an active footprint of approximately 1,690 ha in 2010. This total includes land used for production and test wells, pipelines, access roads and processing facilities.

**Reclamation**

Total reclamation at the MRM by the end of 2010 was 127 ha with 16 ha of permanent reclamation and 111 ha of temporary reclamation. Reclamation activities have been carried out at the airstrip, one of the overburden disposal areas, the raw water intake, old access roads and more recently, on the western side of the MRM ETF. Landscaping work at the ETF and overburden area had not included revegetation by the end of 2010, so it is not included in the totals for that year. JPM is a new mine and therefore only limited temporary reclamation was undertaken in 2010.

Our reclamation plans incorporate both scientific research and Traditional Ecological Knowledge from local Aboriginal people, to ensure the potential end land uses are appropriate for the needs of local communities and other stakeholders.

When permanent reclamation areas are shown to meet regulatory requirements, they can be certified and returned to the Province. The entire reclamation process and subsequent monitoring prior to certification takes several decades to complete. Since the MRM
has only been operating since 2003 and JPM began operations in 2010, there are no certified reclaimed areas. However, preparations are underway to reclaim the sites as shown in Closure, Conservation and Reclamation plans approved by the Province.

Work towards permanent reclamation of a drilling pad (1 ha) in the Three Creeks area and a gravel pit (15 ha) at the Cliffdale in situ operation was undertaken in 2010. As all our in situ sites remain operational there are no certified reclamation areas.

Also in 2010, Shell committed $520,000 towards novaNAIT Boreal Research Institute’s Boreal Reclamation Program. The program brings together people from Aboriginal communities, government, industry and academia to identify best practices for abandoned wellsite restoration. Shell has been involved in the program since 2008 and hosts a demonstration site on a large clearing at PRC.

Soil conservation and revegetation

Soil conservation at our mine sites involves the segregation and stockpiling of five soil types (two upland topsoils, fine textured subsoil, coarse-textured subsoil and peat mineral mixture). The total volume of reclamation materials salvaged from MRM and JPM in 2010 was about 4.7 million m³. Net stockpile volumes totaled 21 million m³.

Land offsets

The AOSP has been purchasing boreal habitat offset lands since 2007 as part of a commitment with the Oil Sands Environment Coalition (OSEC). By the end of 2010, a land area of 374 ha was secured through a partnership with the Alberta Conservation Association. These lands are located in the southern part of Alberta’s boreal zone. Funding of over $800,000 has been provided to date as part of a commitment to spend $2 million over ten years to help mitigate, and partially offset, land and habitat disturbances resulting from our mining operations.

MONITORING AND PROTECTION

Shell has developed an extensive wildlife monitoring program for the AOSP, which incorporates input from Aboriginal people. Using motion sensor cameras in the summer and by assessing animal tracks in the winter we can determine the types of animals present and their direction of travel. Shell’s MRM Wildlife Management Program was created to monitor and mitigate the effects of the mining process on the surrounding environment and to promote the persistence of natural ecological processes in and around the mine area. As part of this program, staff record casual wildlife observations to monitor species that continue to use the area.

Although there was an increase in 2010 bear activity, deterrent strategies worked, eliminating the need for Alberta Sustainable Resource Development to relocate bears.

Wildlife crossing structures (overpasses) in the Peace River region continue to be frequently monitored. Results showed these structures were used in preference to passing under elevated sections of pipeline.

Shell provides support to the Alberta Biodiversity Monitoring Institute (ABMI), an independent body which measures and reports on the health of Alberta’s ecosystems to improve resource management through the government’s land-use framework.

JACKPINE LAKE

Shell completed Jackpine Lake in 2010 – one of the region’s first fisheries compensation lakes for streams impacted by the JPM. The lake is about 47 ha and has a number of best-in-class features including a depth of twice the conventional requirement, natural erosion protection and a unique outlet structure to ensure it is self-sustaining and operates naturally.

Approximately 70,000 cubic metres of topsoil was taken from mine salvage areas to create reclamation areas of about 147 ha around the lake that would preserve the seed bank and place the soil directly into reclamation rather than storing it. Once the reclaimed area was established, we sought advice from members of the Fort McKay First Nation and planted over 2,500 ratroot plants, an important medicinal plant for Fort McKay and other communities.
Shell engages with local people on an ongoing basis and seeks appropriate ways to contribute to communities neighbouring our operations and planned future developments. We contribute through company-wide social investment programs such as the United Way, Shell Community Service Fund, and Shell Environmental Fund as well as oil sands business support for local economic development and capacity building.

Approximately $2.5 million was invested in social programs supporting communities neighbouring our oil sands operations in 2010.

Shell announced its largest single social investment in the Regional Municipality of Wood Buffalo (RMWB) in 2010, investing $2 million over three years in Keyano College. Funding includes support for specific Aboriginal, environmental and technical training programs, a new centre to conduct contractor safety training and a new Fort Chipewyan campus which is scheduled to open in 2011.

Aboriginal Economic Development

In 2010, Shell spent $185 million purchasing supplies and services from Aboriginal companies. By the end of 2010, we had contracted close to $1 billion of business to Aboriginal companies since 2005.

Shell facilitated workshops on health, safety, and environment (HSE) management systems for 18 HSE professionals and business owners in the RMWB Aboriginal business community. The pilot program was developed to introduce Shell’s contractor management practices in addition to fostering a culture of safety among all local Aboriginal businesses working in the oil sands, not just current contractors with Shell.

Engagement

Shell annually hosts open houses to ensure we adequately identify, understand and respond to issues and concerns raised by stakeholders. In 2010, eight events enabled stakeholders to learn more about the proposed Quest carbon capture and storage project. Open houses were also held for our Orion in situ operation...
and Scotford complex. In October, Shell held open houses and met with First Nations and Metis Elders in the communities of Fort McKay, Fort Chipewyan and Fort McMurray to engage in dialogue on our mining operations and growth plans.

In late 2010, over 70 participants, including people from academic institutes, environmental and nongovernmental organizations, Aboriginal organizations, government and business attended a series of dialogue events in Canada and the UK on Shell’s oil sands mining business. With the support of Hoggan & Associates and Viewpoint Learning, the events were designed to seek better understanding of each others’ perspectives, identify common ground and ultimately develop suggestions for improvements in the areas of CO₂, water and tailings, and land and reclamation. Feedback from this and an earlier series of events in 2009 encouraged development of this performance report and its expansion to include our in situ operations. We are planning other engagement events that will continue to help guide performance improvements in our oil sands operations.

More Information
To learn more, visit www.shell.ca/community or call 1-800-250-4355

SOCIAL PERFORMANCE
Social Performance is the term used to describe how we manage the impacts of our business on the communities and societies in which we operate. Those impacts can be positive or negative, but how well we manage them affects the wellbeing of our neighbours and ultimately of our business.

Social performance, which ties together stakeholder engagement, social investment and local and Aboriginal capacity building, is incorporated into our major oil sands operations, including JPM, MRM, Scotford Upgrader, Orion and PRC.

Shell staff frequently seek opportunities to gain input and advice from our neighbours. In Spring, 2010, an independent research firm surveyed 300 people on behalf of Shell’s Scotford Complex. Results showed significant increases in the community’s confidence in Shell as a responsible operator, community contributor and good neighbour since the 2008 survey.
GLOSSARY

**AOSP** The Athabasca Oil Sands Project, a joint venture among Shell Canada Limited (60%), Chevron Canada Limited (20%) and Marathon Oil Canada Corporation (20%). The AOSP consists of the Muskeg River and Jackpine Mines located north of Fort McMurray, Alberta and the Scotford Upgrader, located near Edmonton, Alberta.

**BBL** Barrel.

**BITUMEN** A thick hydrocarbon, referred to as heavy oil.

**CERTIFIED RECLAMATION** Reclaimed areas for which a certificate has been issued under the terms of the Alberta Environmental Protection and Enhancement Act (EPEA), signifying that the terms and conditions of the EPEA approval have been complied with and the lease is returned to the Crown.

**CLIMATE CHANGE AND EMISSIONS MANAGEMENT FUND** The fund set up under the Climate Change and Emissions Management Act that is used to support research, development and deployment of transformative change technologies to reduce greenhouse gas emissions in Alberta. (Source: Specified Gas Emitters Regulation)

**CO₂e** – Carbon dioxide equivalent. The 100-year time horizon global warming potential of a specified gas expressed in terms of equivalency to CO₂. (Source: Specified Gas Emitters Regulation)

**COGENÉRATION** Combined production of heat for use in industrial facilities and the production of electricity as a by-product. (Source: Specified Gas Emitters Regulation)

**COLD PRODUCTION** An in situ production technique used when the bitumen is less viscous and does not require heating to make it fluid enough to be pumped to the surface.

**DIRECT EMISSIONS** The release of specified gases from sources under the direct control of the operating facility expressed in tonnes CO₂e.

**EFFLUENT** Wastewater (treated or untreated) that flows out of a treatment plant, sewer, or industrial facility. (Source: Environment Canada)

**EMISSIONS INTENSITY** The quantity of specified gases released by a facility per unit of production from that facility.

**EMISSION OFFSET** A reduction in one or more specified gases (regulated greenhouse gas emissions) occurring at sites not covered by the Specified Gas Emitters Regulation. (Source: Specified Gas Emitters Regulation)

**EMISSION PERFORMANCE CREDIT (EPCs)** Generated when a facility reduces its Net Emissions Intensity below its Net Emissions Intensity Limit. EPCs are awarded on a tonne CO₂e reduction basis. (Source: Specified Gas Emitters Regulation)

**GJ** Gigajoule. A term used to measure energy use equal to one billion joules.

**GREENHOUSE GAS (GHG)** Mainly, carbon dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O), all of which contribute to the warming of the Earth’s atmosphere. (Source: Government of Alberta, Department of Energy)

**ha** – Hectare. A unit of surface area equal to a square that is 100 metres on each side.

**HEAVY OIL** – Refers to Shell’s upgrading, mineable and in situ oil sands business.
IN SITU Refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection, electrical heating and cold production.

\( \text{km}^2 \) – Square kilometre. A unit of surface area equal to a square that is one kilometre on each side.

\( \text{m}^3 \) – Cubic metre. A unit of volume or capacity equal to 1000 litres.

\( \text{Mt} \) – Megatonne. A unit of mass equal to one million tonnes.

PERMANENT RECLAMATION Landform construction and contouring, placement of capping and reclamation materials and revegetation for terrestrial or wetlands areas. Land cannot be listed under the permanent reclamation category until revegetation has occurred that is reflective of the approved Reclamation Plans.

RECLAMATION Returning disturbed land to a land capability equivalent to what it was prior to mining. Reclaimed property is returned to the province of Alberta at the end of operations.

SEEPAGE The slow movement of water or other fluids through a process medium (e.g., tailings), or through small openings in the surface of unsaturated soil.

SPECIFIED GAS EMITTERS REGULATION Regulates six GHG species – carbon dioxide (\( \text{CO}_2 \)), methane (\( \text{CH}_4 \)), nitrous oxide (\( \text{N}_2\text{O} \)), PFCs, HFCs, and sulphur hexafluoride (\( \text{SF}_6 \)) – for facilities emitting over 100,000 tonnes of \( \text{CO}_2 \) per annum in Alberta.

STEAM ASSISTED GRAVITY DRAINAGE (SAGD) A method of producing heavy oil which involves two horizontal wellbores, one above the other; steam is injected into the upper wellbore and softened bitumen is recovered from the lower wellbore.

SYNTHETIC CRUDE OIL A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.

TAILINGS The residual by-product that remains after the bitumen is separated from the mined oil sands ore; tailings are composed of residual bitumen, water, sand, silt and clay particles.

TEMPORARY RECLAMATION Includes seeding, planting or natural regrowth of vegetation in areas slated to be re-disturbed by future mining or construction activities. This is often done to control erosion and achieve slope stability.

THERMAL PRODUCTION A bitumen recovery technique that includes injecting high-pressure steam underground to mobilize the bitumen, which is then pumped to the surface leaving the sand in place.

TOTAL GHG EMISSIONS Includes GHG emissions from direct and indirect sources.
### CO₂

**OIL SANDS OPERATIONS (MRM, JPM, SCOTFORD UPGRADEr AND IN SITU)**

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total direct emissions (Mt CO₂eq)</td>
<td>2.2</td>
<td>2.3</td>
<td>3.2</td>
<td>3.2</td>
<td>3.7</td>
</tr>
<tr>
<td>Total indirect emissions (Mt CO₂eq)</td>
<td>1.5</td>
<td>1.5</td>
<td>1.6</td>
<td>1.5</td>
<td>1.3</td>
</tr>
<tr>
<td>Total emissions (Mt CO₂eq)</td>
<td>3.7</td>
<td>3.8</td>
<td>4.8</td>
<td>4.7</td>
<td>5.0</td>
</tr>
<tr>
<td>Total CO₂e intensity (kg CO₂e/bbl)</td>
<td>68.3</td>
<td>69.0</td>
<td>84.0</td>
<td>82.8</td>
<td>88.5</td>
</tr>
<tr>
<td>Total CO₂e intensity including offsets (kg CO₂e/bbl)</td>
<td>68.3</td>
<td>69.0</td>
<td>82.1</td>
<td>74.5</td>
<td>45.2</td>
</tr>
</tbody>
</table>

### WATER

**SCOTFORD UPGRADEr**

<table>
<thead>
<tr>
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</tr>
</thead>
<tbody>
<tr>
<td>Total water use (million m³)</td>
<td>5.9</td>
<td>6.2</td>
<td>6.0</td>
<td>6.3</td>
<td>5.5</td>
</tr>
<tr>
<td>Net fresh water consumption (million m³)</td>
<td>3.3</td>
<td>3.7</td>
<td>3.3</td>
<td>3.7</td>
<td>3.1</td>
</tr>
<tr>
<td>Total effluent treated and returned to the river (million m³)</td>
<td>2.6</td>
<td>2.5</td>
<td>2.7</td>
<td>2.6</td>
<td>2.1</td>
</tr>
<tr>
<td>Percentage net fresh water consumption</td>
<td>56%</td>
<td>60%</td>
<td>55%</td>
<td>58%</td>
<td>57%</td>
</tr>
<tr>
<td>Percentage total effluent treated and returned to the river</td>
<td>44%</td>
<td>40%</td>
<td>45%</td>
<td>42%</td>
<td>43%</td>
</tr>
<tr>
<td>Fresh water intensity (bbl water consumed/bbl MRM and JPM bitumen)</td>
<td>0.4</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
<td>0.5</td>
</tr>
</tbody>
</table>

**MRM AND JPM**

<table>
<thead>
<tr>
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<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total water use - Freshwater from the Athabasca, freshwater from other sources and recycled pond water (million m³)</td>
<td>71.2</td>
<td>81.8</td>
<td>92.6</td>
<td>94.7</td>
<td>93.4</td>
</tr>
<tr>
<td>Mine recycle water use (million m³)</td>
<td>59.2</td>
<td>72.1</td>
<td>73.3</td>
<td>74.2</td>
<td>69.6</td>
</tr>
<tr>
<td>Net Athabasca River freshwater consumption (million m³)</td>
<td>8.4</td>
<td>5.7</td>
<td>13.5</td>
<td>15.2</td>
<td>17.5</td>
</tr>
<tr>
<td>Net freshwater from other sources consumption - surface runoff and groundwater (million m³)</td>
<td>3.6</td>
<td>4.0</td>
<td>5.8</td>
<td>5.3</td>
<td>6.3</td>
</tr>
<tr>
<td>Percentage recycled pond water</td>
<td>74%</td>
<td>88%</td>
<td>79%</td>
<td>78%</td>
<td>74%</td>
</tr>
<tr>
<td>Percentage freshwater (Athabasca River)</td>
<td>19%</td>
<td>7%</td>
<td>15%</td>
<td>16%</td>
<td>19%</td>
</tr>
<tr>
<td>Percentage freshwater from other sources (surface runoff and groundwater)</td>
<td>7%</td>
<td>5%</td>
<td>6%</td>
<td>6%</td>
<td>7%</td>
</tr>
<tr>
<td>Freshwater Intensity - Athabasca River (bbl freshwater/bbl bitumen)</td>
<td>1.0</td>
<td>0.7</td>
<td>1.8</td>
<td>2.0</td>
<td>2.4</td>
</tr>
</tbody>
</table>

**IN SITU**

<table>
<thead>
<tr>
<th></th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total freshwater consumption (million m³)</td>
<td>2.0</td>
<td>1.5</td>
<td>2.2</td>
<td>2.1</td>
<td>1.9</td>
</tr>
<tr>
<td>Fresh water intensity (bbl water consumed/bbl in situ bitumen)</td>
<td>4.1</td>
<td>2.8</td>
<td>1.3</td>
<td>1.5</td>
<td>1.6</td>
</tr>
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## LAND & RECLAMATION

<table>
<thead>
<tr>
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<th>2007</th>
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</tr>
</thead>
<tbody>
<tr>
<td><strong>MRM</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total active footprint - mine + plant size (ha)</td>
<td>4,748</td>
<td>4,929</td>
<td>5,578</td>
<td>5,738</td>
<td>6,246</td>
</tr>
<tr>
<td>Permanent reclamation (ha)</td>
<td>17</td>
<td>17</td>
<td>21</td>
<td>16</td>
<td>16</td>
</tr>
<tr>
<td>Temporary reclamation (ha)</td>
<td>11</td>
<td>11</td>
<td>111</td>
<td>111</td>
<td>111</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th><strong>JPM</strong></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total active footprint - mine + plant size (ha)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>3,541</td>
</tr>
<tr>
<td>Permanent reclamation (ha)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0</td>
</tr>
<tr>
<td>Temporary reclamation (ha)</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>6</td>
</tr>
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</table>

## COMMUNITY

<table>
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<tr>
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<th>2010</th>
</tr>
</thead>
<tbody>
<tr>
<td>Social investment spend (millions)</td>
<td>1.8</td>
<td>1.8</td>
<td>1.5</td>
<td>2.7</td>
<td>2.5</td>
</tr>
<tr>
<td>Aboriginal economic development spend (millions)</td>
<td>114</td>
<td>207</td>
<td>212</td>
<td>222</td>
<td>185</td>
</tr>
</tbody>
</table>

---

1. Total CO₂e intensity is calculated on the basis of operational emissions and therefore Jackpine Mine construction emissions (January to July) are not included.
2. This data is intended to show the efforts we are making to offset the impact of emissions from our operations and does not suggest a physical reduction in overall emissions or emissions intensity.
3. Better accounting of water use at our mine sites in 2010 has seen the inclusion of freshwater from other sources.
4. No historical information exists for Jackpine Mine as 2010 is first reporting year.