CARBON CAPTURE AND STORAGE (CCS):
TECHNOLOGICAL PROMISES,
OIL SANDS GROWTH, AND CARBON REDUCTION

David Gooderham
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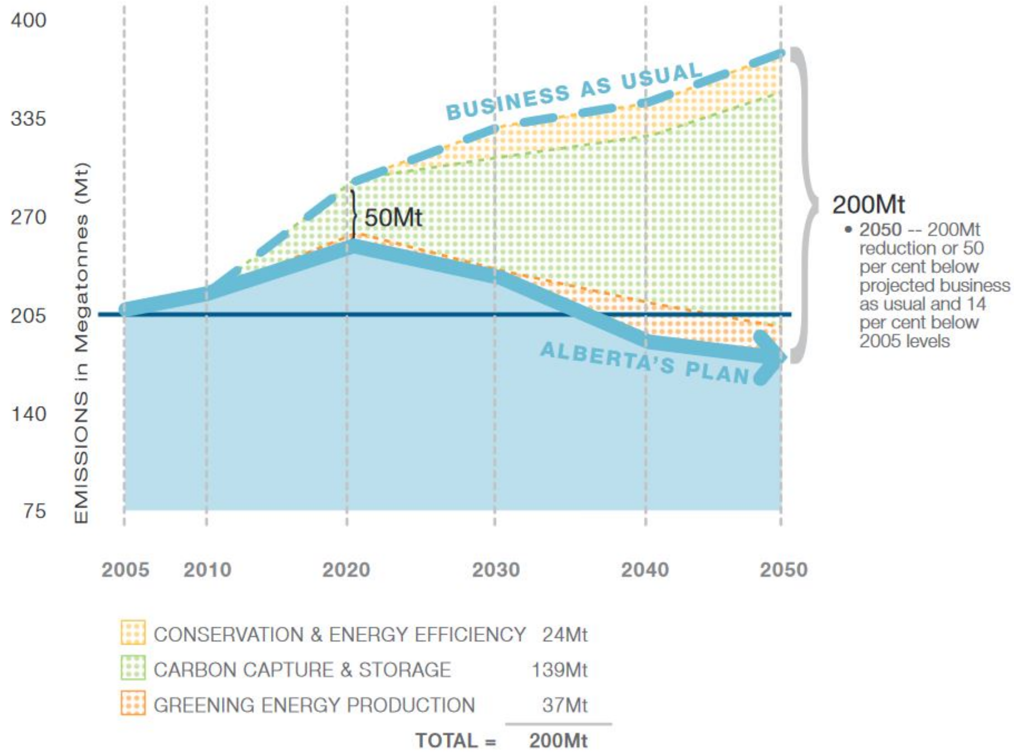
At present, the only existing technology that can separate and remove industrial CO_2 gas and prevent it from entering the atmosphere, albeit at enormous cost, is carbon capture and storage (CCS).

In the case of the oil sands, CCS would capture CO_2 emissions from the flue gases where the fuel for the extraction process is combusted (at the bitumen sites and at processing facilities where natural gas is burned to generate heat and steam) and thus prevent the gases from being released into the atmosphere. The captured CO_2 would be compressed into an almost liquid form, then transported by pipeline and injected deep underground for permanent storage. The technology has its detractors: it is very costly, and some people point to the risk that the CO_2 will later escape into the atmosphere.

Figure A: Graph representing Alberta's 2008 emissions reduction plan



Source: *Alberta's 2008 Climate Change Strategy*, p.24.

Figure A reproduces a graph published in 2008 by the Province of Alberta in a document called *Alberta's 2008 Climate Change Strategy*, when the province launched what it described as the renewal of its climate change policy.[1] At the core of that ambitious new plan was a commitment to deploy CCS technology on a large scale. The premise of the plan was that bitumen production would be able to continue to expand without increasing emissions.

By 2005, Alberta's total emissions, including emissions from its growing oil sands industry, were already at 233 million tonnes (Mt) of CO_2eq[*]. The province's share of Canada's total emissions was then about 31%, reaching 37% by 2014. By 2008, the fast expanding oil sands industry had already become the largest source of emissions growth in the Canadian economy.[2] The Federal Government held back from exercising any regulating role over the industry's emissions.[3] The matter was left entirely to Alberta.

The dotted top line on the graph (Figure A) represents the pathway of Alberta's "business as usual" emissions: that line depicts the projected level of CO_2 emissions that, according to the Alberta government, would be produced in the province in the absence of any new carbon-reduction policies. In the 2008 plan, the projection for Alberta's 2050 "business as usual" emissions was about 384 Mt: that estimate of the annual emissions level by 2050 was largely driven by the continued expansion of oil sands production up to 2050.

The bottom line on the graph shows that under the 2008 plan, total emissions by 2050 were anticipated to be only 194 Mt – an astonishing 200 Mt less than the business-as-usual outcome. Most significantly, the graph shows that by 2050, *139 Mt of that reduction* of CO_2 emissions would be achieved by the large-scale implementation of CCS.

At the heart of Alberta's 2008 plan was the ambition to continue rapid oil sands production, with the declared expectation that by 2020 the installation of CCS would avoid any further increase in the absolute level of emissions. Indeed, the graph shows total emissions in Alberta were expected to begin to decline after 2020 (see the distinct bend downwards in the bottom line on the graph just above the year 2020).

The plan also promised a 50 Mt cut below the baseline projection as early as 2020, of which *more than 30 Mt was expected to be achieved by new CCS technology installations*.

The background of CCS technology

By 2008, when Alberta announced its new climate policy, CCS was already broadly recognized as the most advanced technology in the world available to reduce CO_2 emissions at large "fixed-site" operations. It was not a speculative technology.[4]

[*] Carbon dioxide equivalent (CO_2eq) is a unit of measurement that allows other greenhouse gases (including methane and nitrous oxide) to be converted into an equivalent amount of carbon dioxide that would give the same global warming effect. In this essay, all references to emissions refer to CO_2eq numbers, although in most cases the "eq" abbreviation is not given.

Long before that, basic CCS technology had been used for many years in the U.S. and elsewhere for enhanced oil recovery (EOR) in semi-depleted oil fields. In that application, CO_2 is injected underground into declining oil fields, where the pressure of the injected CO_2 drives the remaining crude oil through existing wells to the surface. There have been many years of successful commercial experience in separating CO_2 at industrial plants, and long experience in the transfer of the gas by pipeline and its injection into semi-depleted oil fields. The technology used for EOR is virtually identical to what is required for CCS, although it was widely acknowledged that a successful application of CCS to sequestering CO_2 at large fixed-site emitters like power plants would require a huge scaling up of the technology.

In addition, by 2008, several other major commercial applications of CCS had been operating for some years. The oldest of those was the Sleipner Project, a Norwegian undertaking that began operation in 1996. About 3000 tonnes of CO_2 per day is stripped from the natural gas produced at a North Sea offshore gas field and injected into a saline aquifer deep below the seabed. In a second installation, at the In Salah gas field in Algeria (operated by BP, Statoil, and an Algerian partner), CO_2 is stripped from natural gas and re-injected underground into a sandstone reservoir. In both gas fields, the CO_2 content of the natural gas extracted is too high to make it marketable, so the excess CO_2 needs to be removed and disposed of.

Canada already had some direct experience with CCS. Weyburn is an EOR project, operated since 2004 by Encana in the Willisdon basin in Alberta. About 3000 to 5000 tonnes of CO_2 per day (1.0 Mt to 2.0 Mt annually) is injected underground into a semi-depleted oil field. The CO_2 is supplied by a 350-kilometre pipeline from a coal gasification plant in North Dakota, where CO_2 is separated from the gases generated during an industrial process that makes synthetic gas (methane). There has been a monitoring system at Weyburn to evaluate the potential of CCS technology since 2004.

In a comprehensive study of CCS called the *Special Report on Carbon Capture and Storage* (2005) a team of 100 specialists under the auspices of the Intergovernmental Panel on Climate Change (IPCC) examined the state of technical knowledge available about the separation of CO_2 in industrial settings. The report, written between 2003 and 2005, looked at the existing level of experience worldwide in transporting CO_2 by pipeline, methods of injection for underground storage, the availability of suitable geological locations for secure underground storage, risks and safety, and costs. With respect to the methodology of separating CO_2 from other gases in industrial settings, the IPCC Special Report assessed the stage of development of the three known processes at that time. Two of the processes, known as *post-combustion* separation and *pre-combustion* separation, were described as “mature market” technologies, meaning that there already existed multiple replications of the technology at sites worldwide. Only a third type of process, known as *oxyfuel combustion*, was then described as still being at the “demonstration” stage of development.

The International Energy Agency (IEA) has also long identified CCS as the essential technology that will be relied upon to capture CO_2 emissions from coal-fired electricity generation plants and other large industrial emitters.[5] In its annual *World Energy Outlook* reports, the IEA has been advocating CCS as the “key abatement option” to achieve large emissions savings at industrial sites. The IEA called for starting large-scale deployment of CCS by 2020, which it regarded at the time as technically feasible. In a special report published in June 2013, entitled *Redrawing the Energy-Climate Map*, the IEA summarized the current state of CCS technology, with particular reference to its availability for installation in coal-fired generating plants:

> *“While the technology is available today, projects need to be scaled-up significantly from existing levels in order to demonstrate carbon capture and storage from a typical coal-fired power plant. Experience gained from large demonstration projects will be essential, both to perfecting technical solutions and driving down costs”.*

— IEA, *Redrawing the Energy Climate Map*, June 2013, p. 25-26 (emphasis added)

The IEA concluded that two conditions must be met before we will see widespread adoption of CCS on a global scale. First, innovation and demonstration projects need to lower the per-tonne cost of capturing CO_2. Secondly, governments must adopt a carbon tax that is *higher* per tonne than the cost of capturing emissions, so as to create an economic incentive for industrial emitters to install this relatively expensive technology.

The abandonment of CCS in Alberta

In 2014, the government of Alberta quietly abandoned its entire CCS strategy. That is a fact not known to most Canadians, and hardly touched on in public discussion.[6]

By then, seven years had passed since the Alberta plan was unveiled. Four carbon capture projects in Alberta were originally announced. Two were later cancelled. No further government funding has ever been committed to support additional projects.

On July 18, 2014, *The Globe and Mail* published an article headlined “Alberta leadership hopeful Prentice lets carbon capture go”. Jim Prentice, a former federal cabinet minister then campaigning to become the new leader of Alberta’s governing Conservative Party, was quoted as follows:

> *“I don’t believe carbon capture and storage is the panacea,” he said. “It’s not capable of achieving the reductions in emissions that are required, and it is expensive, and in certain contexts, it’s quite unproven.”*

— *The Globe and Mail*, July 18, 2014 (emphasis added)

He described CCS as a “science experiment.”

Prentice declared that if he became premier of Alberta, his government would discontinue any further financial support for CCS. This was an extraordinary and far-reaching change of policy. At the time, Mr. Prentice held no elected office. There had been no prior discussion in the Alberta legislature and there was no explanation from the provincial government. CCS technology was the sole foundation for achieving 70% of Alberta’s planned carbon reductions over the next 35 years. In his media interview, Prentice declared that CCS technology was not capable of making the required reductions.

In September 2014, Prentice became premier of Alberta. He confirmed that CCS technology no longer had government support in Alberta.

Soon after, Premier Prentice called a provincial election, which was held in May 2015. By that time, the provincial economy in Alberta had been badly weakened by the deep fall in world oil prices, which began in July 2014. A new NDP majority government took power, under Premier Rachel Notley. During the provincial election campaign the NDP promised to end the government’s “costly and ineffective carbon capture experiment” and reinvest the funding in public transit. In Alberta there was no political support for CCS. After its electoral victory, the new government confirmed that no other government funding was planned to support development of the technology, although it agreed to continue funding the two existing CCS projects.

In that way, Alberta’s entire CCS strategy ceased to exist.

Today in the oil sands there are only two existing CCS projects. One is the “Quest Project”, located at Shell Canada’s Scotford Upgrader near Edmonton. Designed to capture and inject underground 1.2 Mt of CO_2 every year, it became operational in November 2015. That amount represents 35% of the total CO_2 emitted annually from the upgrader’s steam methane units, which produce hydrogen for upgrading bitumen. The capital cost was about $1.35 billion, two-thirds of which was paid for by the Canadian and Alberta governments.

To place the Quest Project in context, currently the level of emissions in the oil sands is increasing by about 4 Mt per year. To halt those regular annual increases, Canada would need to complete more than 3 Quest-sized CCS installations every year. Alberta’s goal, announced in 2008, was to install enough CCS to achieve a 30 Mt cut in the province’s annual level of emissions by 2020 (a target that applied to all kinds of large-scale emitting sources in Alberta, including oil sands facilities). To meet that goal, the province would have needed to complete about 25 Quest-sized installations, all by 2020.

The only other CCS project is the Alberta Carbon Trunk Line, a 240-km pipeline that will transport CO_2 from a fertilizer plant and a bitumen refinery located near Edmonton. The pipeline will transport the CO_2 south to semi-depleted oil fields, where the gas will be injected underground and used for EOR.

In July of 2014, just a week before Mr. Prentice made his announcement, Alberta’s Auditor-General issued a scathing report confirming that the province’s bold plan to install CCS in the oil sands would not meet any of the goals set for 2020. Although the plan was originally announced in 2008, virtually nothing had been done to carry the scheme into effect, according to the findings of the Auditor-General. The report confirmed that apart from the two projects then nearing completion, no other CCS installations were under construction or even planned.

Under *Alberta's 2008 Climate Change Strategy*, CCS technology was supposed to lower the province's emissions level 30 Mt below the "business as usual" level by 2020. The magnitude of that promised cut was equivalent to almost the entire increase of oil sands emissions that in fact occurred over the nine-year period between 2005 and 2014 (when oil sands emissions grew from 34 Mt to 68 Mt). The two completed CCS projects will together cut the annual emissions level by 2.67 Mt, less than 10% of the promised reduction, by 2020. No further reductions by CCS technology are projected after that.

The fate of CCS in the oil sands

Not long after Alberta confirmed that it was dropping support for CCS, a panel of experts on technological innovation in the oil sands industry completed a major report called *Technological Prospects for Reducing the Environmental Footprint of Canadian Oil Sands* (referred to below as "*Technological Prospects*"). The study was originally commissioned by Natural Resources Canada, with the support of Environment Canada. A panel of twelve leading engineers and other experts, the majority of them from Alberta and experienced in oil sands extraction and processing, were appointed to examine whether technological innovation has the potential to significantly reduce the environmental footprint of oil sands development.[7]

The resulting report, which was released on May 26, 2015, reviews the entire range of carbon reduction technologies currently available or under development, including technologies still at the experimental stage that may become commercially available within the next 15 years. The panel explained the scope of their review:

> *Technologies at an early stage of development (i.e., biologically assisted processes) are noted but not necessarily emphasized due to a lack of information and uncertainty about their potential performance. The technologies reviewed include those deemed by the Panel to be <u>commercial in the near to midterm (about 15 years)</u> as well as those that could become viable over the longer term (beyond 15 years).*

— *Technological Prospects*, Introduction, p.9 (emphasis added)

One section of the report (section 6.2) deals specifically with CCS. It identifies *the high cost of carbon capture technology* as the principal barrier to any large-scale adoption of the technology in the near future.

The panel's overall conclusion is significant: the report explains that if oil sands production continues to expand in line with the industry's growth forecasts outlined in 2014, *it will not be possible to achieve any significant reductions in carbon emissions until some time after 2025 or 2030*. In other words, if oil sands production levels continue to grow at a substantial rate, so will emissions. According to the panel, none of the existing or emerging technologies (including CCS) have the capability to substantially lower CO_2 emissions per barrel in oil sands production, at least not for another ten or fifteen years.

In the specific case of CCS, the *Technological Prospects* report concludes that CCS technology will likely have a very limited role in future efforts to reduce emissions in the oil sands.

The panel's broad conclusion is that CCS is too expensive to be adopted during the next ten to fifteen years in the oil sands. Due to the huge capital investment needed for a single CCS installation, the technology is most promising for very large industrial sites (e.g., coal-fired electrical generating plants) that generate high volumes of concentrated CO_2 at a single location. The report explains that, in the oil sands, the most likely future use of CCS will be in applications that capture emissions from hydrogen production in upgraders – a specialized high-emitting industrial activity connected to processing bitumen at open-pit mining operations. But upgraders are a relatively small part of the oil sands emissions problem in Alberta.

In comparison, the fastest expanding area of bitumen production – and therefore the fastest growing source of emissions – is in situ (underground extraction) operations, which are smaller in scale. The panel was not optimistic about the prospect that CCS can ever become an affordable technology at these smaller-scale in situ sites, because they do not offer the needed high volume of emissions to justify the cost:

> *More expensive would be the capture of CO_2 from <u>in situ projects</u> because these represent <u>smaller and geographically dispersed sources of emissions</u>.*
>
> — *Technological Prospects,* p. 130 (emphasis added)

Even after the expensive technology is installed, operating expenses are substantial. The "capture" stage, which involves compressing huge volumes of separated CO_2 gas, is a highly energy-intensive process; that process consumes a lot of natural gas, which adds to costs (and ironically also adds to carbon emissions at the site).

The panel's report makes it clear that, mainly for reasons of cost, carbon capture technology is unlikely to have any significant impact on reducing oil sands emissions until after 2025-2030, and even then, its future application may be limited to a relatively small portion of the industry's future emissions.

The panel identifies another difficulty that may impede efforts in the future to adopt CCS technology:

> *… retrofitting an existing facility to capture CO_2 is generally more expensive per tonne of CO_2 sequestered than designing a new one to include CCS from the start ... This is important in a fast-growing industry such as the oil sands where <u>the rapid pace of development may "lock in" existing capital equipment and processes.</u>*
>
> — *Technological Prospects,* p. 128 (emphasis added)

In other words, ten years from now (by which time CCS may become an affordable technology) it will be too costly to retrofit all the newer facilities that, in the interim, will have already begun production. We will have locked in a substantial proportion of production that will be operating with the older, more carbon-intensive methods.

Perhaps the most unusual part of the report – unusual because we do not normally see this kind of discussion in Canada about the oil sands – is the panel's note of caution about the expected pace of technological innovation. The panel members offer us a fascinating analysis of why innovations often move slowly in the oil sands industry, and why there is no "breakthrough technology" on the horizon:

> *On the business side, the scale and capital intensity of oil sands projects encourage a preference for proven technologies. Risk aversion may <u>lock in existing technologies</u> and delay deployment of environmentally superior alternatives. Another impediment is <u>the long lead-time for technological development in extractive industries such as the oil sands</u>, which often stretches from 10 to 20 years. Also, innovation is inherently uncertain: most of the technologies now being tested may fail or not prove commercial while the remainder may take many years to move from concept to market.*
>
> — *Technological Prospects,* Executive Summary, p. xxi (emphasis added)

Individual oil sands projects can cost up to \$10 billion or even \$15 billion dollars each. Between the initial design process and the eventual startup of production, five to eight years might intervene. Another variable is changing world oil prices. In this context of very long lead times and economic uncertainty, the risks of committing to new technologies are evident. The panel describes it this way: "The financial risks of implementing costly new technologies at the scale required are … immense".

The failure of Alberta's 2008 plan based on CCS technology is a matter of enormous consequence. CSS was assumed to be the means of achieving 70% of Alberta's entire carbon reduction objective up to 2050.[8] It was the technological solution that was going to allow bitumen production to continue to expand after 2020, while *simultaneously achieving absolute reductions* in CO_2 emissions. It was almost a miracle.

At present, there is no alternative technology that can take its place.

The energy-intensity of oil sands extraction

The oil sands consist of immense formations of clay, silt, and sand particles coated with an outer layer of tar-like bitumen. A unique feature of extracting bitumen from the oil sands, in comparison to recovering crude oil in the form it is found in most other places in the world, is that the process requires massive amounts of heat and steam to separate the bitumen from the sand and clay in which it is embedded. Bitumen in its natural state in the earth has a *high viscosity*. Heat must be used to make it melt – to make it flow.

Most of the oil sands formations in Alberta (which contain 170 billion barrels of bitumen, the third largest crude oil reserve in the world after Saudi Arabia and Venezuela) are located too deep underground for surface mining. Surface mining is gradually declining in relative importance, although its vast open pits and tailings ponds remain the most visible symbol of the industry. The most common extraction method being developed now, called "in situ", involves drilling into deep deposits of oil sands, perhaps 400 to 600 feet underground, and then drilling two horizontal wells – or series of wells – one below the other, which may extend a kilometer or more in length.

In the in situ process, high-pressure steam is injected underground for lengthy periods, eventually causing the bitumen to soften and separate from the granular sand and clay in which it is embedded and drain through the earth into the lower well from which it is pumped to the surface.

The Government of Canada's most recent emissions report, the *National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada* (released April 13, 2017), provides this succinct description of the in situ process:

> *The steam-assisted gravity drainage (SAGD) process used to extract crude bitumen involves injecting large amounts of steam into the producing formation, where the heat from the steam allows the crude bitumen to flow and be extracted. The steam is generally produced by combusting natural gas, resulting in emissions. Since 2005, total natural gas consumption in this subcategory has increased over 75% (Statistics Canada 1990-2016), and SAGD production has increased over 900% (AER 2016).*

— *National Inventory Report 1990-2015*, p. 57

That natural-gas-driven process explains the high level of CO_2 emissions for each barrel of bitumen produced.

Total oil sands production has more than doubled since 2005, increasing from 1.006 million barrels per day (bpd) in 2005 to 2.306 million bpd in 2014. The April 2017 *National Inventory* report confirms that emissions from the oil sands sub-sector have also doubled over that period:

Figure B: Oil sands emissions 2005 to 2015 (Mt CO_2eq)

	2005	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
Oil sands	35	53	55	60	64	68	71

Source: *National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada,* Environment and Climate Change Canada (April 13, 2017), Table 2-12.

Reducing carbon intensity per barrel

The question now is whether other kinds of new and emerging technologies can offer a way to reconcile the currently planned expansion of oil sands production with the need to achieve deep cuts to Canada's total emissions.

Improvements in technology and advances in extraction methods over the past twenty-five years have achieved some success in lowering the amount of energy (fossil fuel burned) that is required to extract each barrel of bitumen. A huge amount of natural gas is combusted to generate the heat and steam required for the extraction process. By improving efficiency, less CO^2 is released for each barrel of bitumen that is produced.

Those gains are spoken of as improvements in *carbon intensity*. In this approach, large amounts of CO_2 are still emitted into the atmosphere, but the amount of emissions per barrel is reduced.[9]

In contrast, in the case of CCS technology, the approach is to *capture the CO_2 gas and make sure the gas does not escape into the atmosphere at all*.

To provide a context for this discussion, a useful measure is that approximately 0.1 tonne of CO_2 (equivalent to 100 kilograms) is emitted per barrel during the oil sands production process – production of ten barrels adds up to roughly one tonne of CO_2 emissions. Carbon intensity per barrel is usually given in kilograms: the most recent data indicates that the average emissions intensity of all oil sands operations in 2015 (including in situ, mining, and upgrading) was 79 kg CO_2eq per barrel. The *National Inventory Report* (April 13, 2017) describes the gradual decline of carbon intensity over the past twenty-five years:

> *… the intensity of oil sands operations themselves declined steadily from 1990 (122 kg CO_2eq per barrel) until about 2005 (90 kg CO_2eq per barrel). From 2005 to 2010, the intensity remained relatively flat. Since 2010, emissions intensity in the oil sands has continued to decline as the industry reduced the fuel [i.e. natural gas] combustion requirements per barrel extracted.*

Therefore, over the initial fifteen years between 1990 and 2005, emissions intensity per barrel dropped about 26%. During the next five years, between 2005 and 2010, the trend was "flat". After 2010, emissions intensity began to decline again, dropping approximately another 16% over the next five years to 2015, down to an average 79 kg CO_2eq per barrel.

Notwithstanding that documented improvement in carbon emissions intensity per barrel, *total oil sands emissions* in Alberta more than quadrupled between 1990 and 2015, from 15 Mt to 71 Mt.

Proponents of rapid expansion of bitumen production often make the claim that carbon intensity (emissions per barrel) has been improving. That assertion was made, for example, by Joe Oliver, then Canada's Minister of Natural Resources, in a series of speeches in 2014 to political and business audiences in the United States. Oliver was campaigning to build support in the United States for approval of the Keystone XL pipeline. In a speech on March 4, 2014, in Houston, Texas, he gave this assurance to his American audience about the environmental record of oil sands development in Canada:

> *Emissions per barrel have been reduced by 26 percent between 1990 and 2011.*

— speech, Joe Oliver (emphasis added)
http://www.nrcan.gc.ca/media-room/speeches/2014/15623

It is a positive message. That same claim, in more or less identical language, can be seen on government and industry websites in Canada.[†]

The claim is partly accurate, but misleading in a fundamental way. The truth is that carbon intensity did improve by 26% between 1990 and 2005. The problem is that the comparatively small "gain" in the reduction of the amount of CO_2 per barrel (26% over 15 years) was more than offset by the huge increase in the number of barrels produced over the same period. Between 1990 and 2011, production quadrupled from less than 400,000 bpd to 1.7 million. Total emissions increased in that period, from 15 Mt to 55 Mt a year. Despite the reduction in carbon intensity per barrel, the total level of emissions more than tripled.

Again, if we look at the ten years between 2005 and 2015, the annual level of oil sands emissions doubled – from 35 Mt to 71 Mt. Even with a 16% decline in carbon intensity during 2010-2015, total oil sands emissions continued to grow in absolute terms.

Carbon pricing in the oil sands

One of the impediments to rapid technological innovation, according to the *Technological Prospects* report, is the relatively low price and abundant supply of natural gas in Alberta:

> *As for resource inputs, natural gas, one of the most important inputs in oil sands operations, is widely used to generate steam, electricity, and hydrogen (in upgrading). Low gas prices, however, discourage investments in, for example, solvent-assisted in situ recovery, use of alternative sources of power like hydro, and improvements in energy efficiency, all of which would reduce GHG emissions.*

— *Technological Prospects,* Executive Summary, p. xxi (emphasis added)

As long as natural gas is cheap, there is no big incentive for oil sands producers to search out alternate methods of extracting bitumen – that is, methods that do not depend on

[†] Natural Resources Canada website, July 25, 2017: "Technical advances in the oil sands have helped to create more energy efficient practices and to decrease GHG emissions in the oil sands." (http://www.nrcan.gc.ca/energy/oil-sands/18091)

burning natural gas to generate steam – because the alternate methods are more expensive.

The *Technological Prospects* report acknowledges that Alberta's Specified Gas Emitters Regulation (the SGE regulation) has not created enough of an economic incentive to make a difference:

> *While Alberta's Specified Gas Emitters Regulation does impose a carbon compliance price on large emitters (as one option should they not meet annual CO_2 emission intensity reduction targets of up to 12%), it is only a modest economic incentive for firms to invest in new technologies that reduce GHG emissions, amounting to only a few cents per barrel.*
>
> — *Technological Prospects,* Executive Summary, p. xxi (emphasis added)

The *Specified Gas Emitters Regulation* (SGER) came into force in Alberta in July 2007. The policy rationale was that a monetary penalty on CO_2 emitted above a defined limit per barrel would give oil sands operators an *economic incentive* to invest in technological innovations to reduce emissions intensity. The SGER was based on a nominal carbon price of $15 per tonne.

The Alberta regulation required facilities to achieve carbon intensity reductions of 12%, measured over a set period of time. New plants were entitled to a complete exemption for their initial three years of operation. After that, within the next six years, they were required to show a 12% reduction of emissions per barrel (the "performance standard"), measured against what they achieved in their own third year of operation.

Under the SGER scheme, however, achieving the specified emissions reductions was not mandatory. In lieu of attaining the prescribed reductions, a producer had the option to simply make the required penalty payment to a government-administered fund. The weakness of the SGER was due to the low amount of the non-compliance payment. The carbon price was levied *only on the share of emissions that exceeded the performance standard*. The other 88% of the emissions at a production facility were emitted free of charge. The actual cost to a producer who failed to meet the standard worked out to about 20 cents per barrel.[10]

Minor changes to this scheme were announced on June 25, 2015. The required emissions reduction per barrel (the "performance standard") was raised to 20%, instead of 12%. The carbon price was raised to $30 per tonne, effective January 2017. The cost for non-compliance would still be only about 60 cents per barrel.

In its key elements, the SGER remained unchanged for ten years.

Starting in January 2018, further changes to Alberta's carbon pricing regulation will take effect. The new system is called the Carbon Competitive Regulation (CCR). It was announced as part of the *Alberta Climate Leadership Plan*, released on November 20, 2015.[11]

The new regulation retains many of the defining features of the old SGER scheme. The carbon price will remain at $30 per tonne. Oil sands producers are still not obligated to pay the carbon price on the full amount of CO_2 released at their facilities – but only on the fractional share of their emissions that exceed the permitted amounts under a new scheme of "emissions rights".

Under the new CCR scheme, all oil sands producers will be allocated (at no cost) an amount of "emissions rights" (i.e., a permit allowing each company to release a specified quantity of emissions free of charge.) Each producer will be obliged to pay the carbon price only on the portion of their emissions that *exceeds* their allotted emissions rights.[12]

This new system offers economic incentives to the most efficient oil sands companies – those who achieve the lowest emissions per barrel. Those top producers will pay no carbon levy, provided they can keep total emissions at their facilities within their allotment of emissions rights. Less efficient producers – or producers operating at sites where poor-quality bitumen resources require more energy to extract each barrel – will exceed their emissions rights and pay the carbon price on that portion.

Despite this new system of carbon pricing, Alberta's Climate Leadership Panel conceded in its November 20, 2015 report that total emissions in the oil and gas sector will continue to grow to 2030.[13] The new CCR regulation may slow down the rise of oil sands emissions to some degree, but it will not substantially alter the rising trend.

The dilemma, acknowledged by the panel, is that stronger measures to more rapidly drive down emissions per barrel would be incompatible with plans to continue expanding oil sands production.

The Alberta panel concluded that "more stringent" measures would make Alberta's industry uncompetitive (see *Climate Leadership* report, "Outcomes and Impacts", at p. 11). If Alberta were to adopt more aggressive policies aimed to substantially cut the projected growth of oil sands emissions, the additional costs (incurred by producers to adopt new technologies required to reduce emissions per barrel) would make Alberta's bitumen production more expensive, and therefore uncompetitive against lower-cost foreign producers.[14] That was the panel's view. The costs of production per barrel in the oil sands industry are already among the highest in the world, due to the enormous capital cost of the extraction facilities and comparatively high operating costs. Low oil prices have further narrowed the margin for profitably developing new production sites.

Technology and oil sands emissions growth to 2030

Unfortunately, the available evidence shows that between now and 2030, technological innovation cannot lower carbon intensity fast enough to alter the existing trend, in which emissions levels continue to increase in step with rising production.

The Government of Canada's most recent emissions projections to 2030 are found in the *Greenhouse Gas Emissions Reference Case* (December 22, 2016) data. The *Reference Case* projections take into account all government emissions reduction policies in place or announced as of November 1, 2016. In the case of the oil sands, they take into account expected improvements in carbon intensity over the next decade:

Figure C: Oil sands emissions and production

	2005	**2014**	**2020**	**2030**	**change 2014-2030**
Emissions	34	68	87	108	**+40 Mt CO_2eq**
Production	1.066	2.306	3.220	3.967	**+1.661 million bpd**

Source: *Canada's 2016 Greenhouse Gas Emissions Reference Case*, Environment and Climate Change Canada, December 22, 2016, Table A7.

This is the best evidence we have. It tells us that if we continue to expand oil sands production as currently projected, by 2030 annual emissions in that industry will be 40 Mt higher than they were in 2014.

It is unlikely that any improvement in carbon intensity is going to change that outcome. To understand why, it is useful to return to the *Technological Prospects* report published in May 2015.[7] The full title of the document elaborates on the scope of the inquiry: "The Expert Panel on the Potential for New and Emerging Technologies to Reduce the Environmental Impacts of Oil Sands Development". The original request from the government presented this question: *"How could new and existing technologies be used to reduce the environmental footprint of oil sands development on air, water, and land?"*

The report is unusual because it provides us with the results of a comprehensive effort to address the key issue: over the next fifteen years, can technology stop the continued rise of oil sands emissions, if production is still expanding?

The panel's conclusion is that "there is no breakthrough technology to reduce GHG emissions on the horizon". Here is how the panel summarizes its findings:

> *Based on the analysis above, the Panel found that although technology available on the short- to midterm horizon could reduce the environmental footprint on an <u>intensity basis</u>, they would not bring about <u>absolute reductions</u> at projected production growth rates. This is especially true for GHGs and tailings.*

— *Technological Prospects*, section 7.3 "Towards Reducing the Absolute Footprint of Oil Sands Production, page 157 (emphasis added)

In the context of that report, "midterm" means within the next fifteen years. Based on 2014 projections of production growth, the panel concludes that the level of CO_2 emissions will continue to increase through the next decade. It will not be possible to achieve any *absolute reductions* of emissions in the oil sands, not before about 2030.

The panel gives two principal reasons why GHG emissions from the oil sands will continue to increase in absolute terms through the next decade:

First, by its nature, oil sands production is both energy and resource intensive: a typical surface mine processes 2.4 barrels of fresh water per barrel of oil and disturbs 9.5 hectares of land per million barrels of production; for its part, an average in situ operation generates 82 kg of CO_2eq per barrel of production (Grant et al., 2013). By definition, energy and resource intensity results in a heavy environmental impact.

— *Technological Prospects,* section 7.3, p. 158

Given the existing technology, the extraction of bitumen will continue to require the consumption of large amounts of natural gas. There are no technological innovations on the near horizon that will shift the extraction process away from that main reliance on using natural gas combustion to generate steam. Improvements of energy efficiency in the existing steam-driven technologies are possible (that will help drive down CO_2 emissions per barrel), but they will only be "incremental".

Chapter 4 of the report examines a range of prospective new technologies that are currently being pursued for in situ production. One category, described as "incremental process improvement", comprises new methods that aim to *use the existing natural gas and steam-based process more efficiently* (and thereby lower the amount of natural gas required to extract a barrel of bitumen). These improvements still rely essentially on the existing natural gas-based approach.

A number of other, more ambitious technologies, still at the experimental stage, inject chemical or solvent additives into the bitumen reservoir, in combination with the steam. The additives enhance the effectiveness of the steam process, allowing less natural gas to be used (and therefore reducing emissions per barrel of bitumen). These are referred to as *chemical additive* and *solvent-assisted* technologies. They still depend on the existing natural gas / steam process.

An extract from the panel's discussion of solvent-assisted technologies reveals some of the uncertainties and challenges of these proposed solutions, even once they have reached the experimental and field test stage:

The addition of solvents (mostly various <u>light hydrocarbons, such as gas condensates or butane</u>) reduces the temperatures and pressure of the steam required to mobilize bitumen in situ, and hence the energy and water input needed for production. This decreases GHG emissions associated with production. Solvents, however, have two important limitations. Used by themselves, they reduce bitumen viscosity more slowly than steam … <u>Solvents are also expensive</u> (as processed products, they cost more than the raw bitumen in the ground): thus <u>the economics of solvent-assisted production depend crucially on the recovery and reuse</u> of the bulk of the solvents being injected (according to the Panel, about 85% recovery is required to make these technologies economic).

— *Technological Prospects,* section 4.2 "Solvent-Assisted Technologies", p. 89-90 (emphasis added)

One of the challenges is that individual bitumen reservoirs vary in their composition, so that the technologies need to be customized for each location.

The report concludes that, based on available trials and test results, solvent-assisted technologies can reduce carbon emissions per barrel by 25 to 35%. But that scale of envisioned reduction will only occur at the particular sites where the new technology is successfully adopted – it does not represent a measure of across-the-board improvements that will quickly reduce the industry average for all in situ production. Even as some operators move to solvent-assisted technology, other operators will be "locked in" to the older technology. The expense of the technology will also be a factor. As long as natural gas is cheap and the carbon compliance price remains low, the incentive to shift to solvent-assisted technologies will be weak. While solvent-assisted technologies will be deployed in the near and midterm (and some companies have already moved to commercial application), carbon intensity improvements across the industry will be incremental, spread over the next decade.[15]

The panel identifies another factor that can negate expected improvements in carbon intensity per barrel:

> *There are limits to those improvements, however, because <u>future production will increasingly come from lower-quality deposits</u> (i.e., thinner, less permeable, more geologically heterogeneous) that are likely to require more, rather than fewer, inputs to produce.*
>
> — *Technological Prospects*, section 4.5 "Conclusions", p. 97

A shift of production activities in future to lower-quality deposits will offset some of the expected gains from solvent-assisted processes and other efficiency improvements. The report discusses the consequences of "the progression of development from the most accessible deposits, richest in bitumen, to lower-quality deposits that are more technologically challenging and expensive to recover."

> *Since larger environmental impacts are often associated with harder to develop deposits, these impacts can be expected to grow without technological improvements as developers gradually develop <u>less attractive deposits that are deeper, thinner, less permeable, and with lower bitumen saturation</u>.*
>
> — *Technological Prospects*, section 7.1.1 "Reservoir Quality, p. 134

If there were any credible evidence available to support promises that technology will be able to lower oil sands emissions, the perfect opportunity to examine that question would have been the Federal Government's recent *Review of Related Greenhouse Gas Emissions Estimates for the Trans Mountain Expansion Project* (also known as the "Kinder Morgan Emissions Assessment"), which released its final report on November 25, 2016. Adopting the NEB's projections of future oil sands growth up to 2040, the report confirmed that oil sands emissions will continue to increase up to 2030, and that expanding oil sands output will be the main driver of emissions growth in the Canadian economy:

> *The growth in emissions to 2030 is driven largely by growth in the upstream oil and gas sector and, in particular, from the oil sands. ECCC [Environment and Climate Change Canada] projections indicate that GHG emissions from the oil sands could increase from 62 Mt in 2013, to 90 Mt in 2020 and up to 116 Mt in 2030.*‡
>
> — *Kinder Morgan Emissions Assessment*, November 25, 2016, section B.2.2, p. 22 (emphasis added)

Section B.2.5 is the only portion of the Kinder Morgan Emissions Assessment that directly addresses the key question of whether technology might enable the oil sands industry to reduce emissions, if production continues to expand. It provides only this vague assurance:

> *Over time, new technologies and policies will be developed that will change the emissions intensity and economic feasibility of oil production both in Canada and globally, as well as act to change the attractiveness of alternatives to oil.*
>
> — *Kinder Morgan Emissions Assessment*, November 25, 2016, section B.2.6, "Canadian Climate Change Commitments and Oil Sands Production", p. 28

The availability of these unspecified "new technologies" is conveniently set in the indefinite future. There is no discussion about *when*, or by how much, these technologies will be able to reduce the emissions intensity of oil sands production. In truth, the efficacy, cost, and potential availability of these new technologies is so uncertain that the report is unable to offer Canadians any estimate of when, or by what amount, they might in future reduce oil sands emissions. Despite these assurances about the future benefits of "new technologies", the report agreed that – up to 2030 at least – oil sands emissions will continue to grow in absolute terms.

Conclusion: the path we are on

Canada's 2016 Greenhouse Gas Reference Case, published on December 22, 2016, shows that the projected increase in total oil sands production between 2014 and 2030 will *increase our annual emissions by 40 Mt* (see Figure C, on page 14). That increase is based on an expected 1.6 million bpd expansion of oil sands output in that period.[16]

There is no technological solution that can significantly reduce that emissions outcome if we expand production as we currently plan to do.

‡ This November 25, 2016 report showing oil sands emissions rising to 116 Mt by 2030 was based on data in *Canada's Second Biennial Report on Climate Change*, released in February 2016, which assumed that oil sands production would reach 4.258 million bpd by 2030. A subsequent oil sands projection published in the *Reference Case* in December 2016 (see Figure E at p.18) showed production reaching only 3.967 million bpd by 2030, with oil sands emissions rising to 108 Mt. For the most recent NEB projections of oil sands production (October 2017), see Note 16.

There are also economic limits on the extent to which new policies can require producers to adopt available new technologies that could substantially lower emissions per barrel. The problem is costs and competitiveness. The Alberta government's *Climate Leadership* report, released on November 20, 2015, recommended some improvements to the performance standard and carbon price scheme that applies to oil sands emissions. But the report concluded that more aggressive policies to substantially reduce oil sands emissions are "not tenable", because they would raise production costs for Alberta producers and make the industry uncompetitive against lower-cost oil production in other jurisdictions.[14]

> *In the meantime, imposing policies in Alberta that are more stringent than what we have suggested is not tenable, until our peers and competitor jurisdictions adopt policies that would have a comparable impact on their industrial sectors.*

— *Climate Leadership*, p. 11

The argument is that more stringent emissions reduction policies in the oil sands will result in "sacrificing wealth and prosperity" in Canada (i.e., lower production levels) while other countries increase their output to replace our exports.

Canadians have been repeatedly assured that Alberta's "absolute cap of 100 Mt a year" on oil sands emissions, announced in November 2015, will limit the impact of the expanding industry on Canada's total emissions. But the "cap" is set so high – providing an upper limit of 100 Mt for the annual level of oil sands emissions – that it will have no impact at all on limiting the growth of oil sands emissions before 2030. In other words, notwithstanding the cap, oil sands emissions will continue to increase in Alberta over the next decade, as they are projected to do in the *Reference Case*.[17]

At the end, we are left with questions whether our plan to continue the expansion of oil sands production to 2030 can be reconciled with our climate commitments.[18]

The oil sands industry is the largest single source of emissions growth in the Canadian economy. It is offsetting most of the emissions reductions we are achieving in other economic sectors. There is no magical technology waiting in the wings to fix everything so we can have our production increases and our carbon reduction too.[19] Once we acknowledge that truth, we can begin to have an honest discussion about solutions.

NOTES

1. Alberta's 2008 Climate Change Strategy

The document setting out details of Alberta's 2008 plan can be found at:
http://aep.alberta.ca/forms-maps-services/publications/documents/AlbertaClimateChangeStrategy-2008.pdf

In addition to a commitment to support large-scale adoption of CCS technology in the oil sands industry, the Alberta provincial government in 2007 enacted the *Specified Gas Emitters Regulation* (SGER), which imposed a financial levy on oil sands operators who failed to comply with new performance standards aimed to achieve gradual reductions of emissions per barrel at oil sands production facilities.

It turned out, however, the financial levy under the SGER was so modest that it never provided a sufficiently robust economic incentive to induce oil sands producers to invest in CCS technology (see Note 10 below for a more detailed discussion of the SGER).

Alberta's 2008 scheme remained in place for about seven years, until Jim Prentice announced in 2014 that the Alberta government would no longer provide financial support for CCS technology. That decision coincided with the collapse of world oil prices in the second half of 2014.The fall of oil prices by that time had ended any realistic possibility that oil sands producers would undertake massively expensive investments in CCS technology.

2. The Government of Canada's emissions projections to 2030

In December 2016, the Government of Canada published *Canada's 2016 Greenhouse Gas Emissions Reference Case*, which provides emissions projections up to 2020 and 2030. The *Reference Case* report is based on actual emissions data up to 2014 (emissions results for 2015 did not become publicly available until April 2017). Emissions are divided into seven main economic sectors, with detailed breakdowns for specific industries and types of activity in each sector.

The *Reference Case* projections for all seven economic sectors are shown in Figure D:

Figure D: Emissions projections to 2020 and 2030 (Mt CO_2eq)

	2005	2014	2020	2030	Change 2020-2030	Change 2014-2030
Electricity	118	78	64	34	-30	**-44 Mt**
Transportation	171	171	168	157	-11	**-14 Mt**
Oil and Gas	159	192	201	233	+32	**+41 Mt**

Heavy Industry	88	76	85	97	+12	**+21 Mt**
Buildings	85	87	89	94	+5	**+7 Mt**
Agriculture	70	73	72	74	+2	**+1 Mt**
Waste and Others	56	54	51	53	+2	**-1 Mt**
Total	**747**	**732**	**731**	**742**	**+12**	**+10 Mt**

Source: *Canada's 2016 Greenhouse Gas Emissions Reference Case* Environment and Climate Change Canada (December, 2016), Table A5. Environment Canada notes that numbers may not sum due to rounding. I have added the two columns on the right showing the projected changes for each sector.

The record shows that, between 2005 and 2014, the electricity sector was by far the largest source (and almost the only source) of emissions reductions in the Canadian economy. However, that remarkable 40 Mt cut in electricity emissions over nine years was offset by a 33 Mt increase in oil and gas emissions. Based on the *Reference Case* projections, the same pattern is going to continue: between 2014 and 2030, electricity emissions are expected to decline by another 44 Mt, but oil and gas sector emissions (almost entirely driven by oil sands expansion) will grow by 41 Mt. Apart from a very modest expected cut in transportation emissions (14 Mt), no other economic sector is projected to show any meaningful reduction between 2014 and 2030.

Figure E, based on Table A6 in the *Reference Case,* shows emissions projections for the oil and gas industry. Oil and Gas is the largest emitting sector, accounting for 26% of Canada's total emissions. The oil sands sub-sector accounts for virtually all of the expected emissions growth expected over the period 2014-2030 in this sector:

Figure E: Oil and gas sector emissions by production type (Mt CO_2eq)

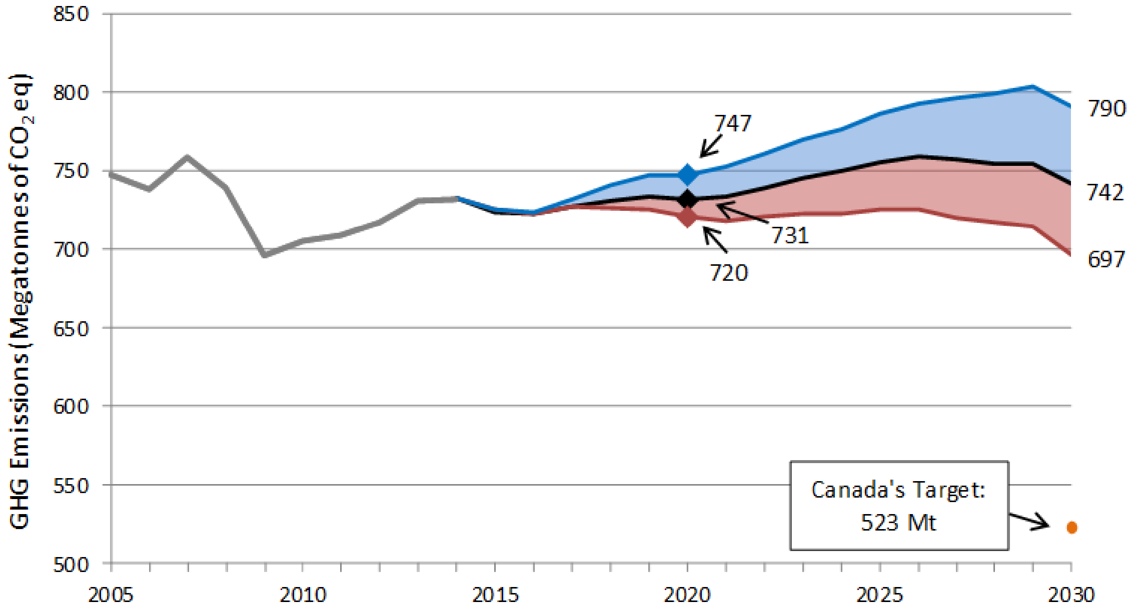
	2005	**2014**	**2020**	**2030**	**Change 2005-2030**	**Change 2014-2030**
Natural Gas Production and Processing	58	57	50	56	-3	**-1 Mt**
Conventional Production	31	36	31	32	+1	**-4 Mt**
Oil Sands	34	68	87	108	+74	**+40 Mt**
Oil and Natural Gas Transmission	12	10	9	10	-3	**0 Mt**

Downstream Oil and Gas	23	23	23	23	0	**0 Mt**
Liquid Natural Gas Production	0	0	0	3	+3	**+3 Mt**
Total	**159**	**192**	**201**	**233**	**+73**	**+41 Mt**

Source: *Canada's 2016 Greenhouse gas Emissions Reference Case* Environment and Climate Change Canada (December 2016), Table A6. Environment Canada notes that numbers may not sum due to rounding. I have added the column on the far right, showing the projected change from 2014 to 2030.

Figure F, reproduced from the *Reference Case* report, provides a convenient picture of our current situation:

Figure F: Canada's domestic emissions projections in 2020 and 2030 (Mt CO_2eq)



Source: *Canada's 2016 Greenhouse Gas Emissions Reference Case*, 1. Introduction, Table 2.

The middle line is the "reference case" projection of Canada's total emissions to 2030. The other tracks indicate two other possible emissions paths, depending on the future rate of economic growth, long-term oil prices, etc. Strong growth could push the projected level up to 790 Mt. The Government of Canada's 523 Mt target for 2030 (a commitment made at the Paris Climate Conference in 2015) is shown in the lower right corner.

We see a sharp break in the emissions trend between 2007 and 2010. Canada's annual CO_2 emissions peaked in 2007 at 750 Mt. The numbers fell in 2008-2009 as a result of the 2008 financial collapse. Most of that unprecedented drop had nothing to do with any policy by governments to manage carbon emissions. The numbers fell mainly because economic activity collapsed. The low point was 689 Mt in 2009. The total drop was 61 Mt, an extraordinary reduction of emissions within the space of two years. That illustrates how sensitive emissions are to economic growth.

Only a small share of the emissions reduction during 2008-2009 can be attributed to deliberate carbon reduction policies. Five years earlier, in about 2003, the Ontario government made a decision to shut down all of its coal-fired electricity plants. The implementation of that policy in Ontario was well advanced even before the 2008 financial crisis. Overall, between 2005 and 2014, the annual level of emissions in the electricity sector across Canada fell by about 40 Mt – and about 30 Mt of that reduction occurred in Ontario. A portion of those electricity emissions cuts took place in 2008-2009. But most of the very large decline in 2008-2009 was due to the sharp recession.

Once economic growth rebounded after 2009, emissions in some sectors (i.e., heavy industry, transportation, and buildings) that had declined during the recession also rebounded. However, some types of industrial activity suffered permanent contractions, in part as a result of globalization and the shift of manufacturing to low-wage countries.

Canada's GHG emissions in 2015 were 722 Mt: see the *National Inventory Report 1990-2015: Greenhouse Gas Sources and Sinks in Canada*, published on April 17, 2017 (the *Executive Summary* is available at https://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=662F9C56-1). This new report includes some revisions to previously reported results for 2014 and preceding years. Total emissions in 2005 are now reported as 738 Mt, down from 747 Mt shown in Figure D. The revised total for 2014 is 727 Mt, instead of 732. This corrects over-reporting of waste sector emissions by 6 Mt in recent years, and over-reporting of transportation emissions in 2005. The main trends are unchanged. Using this new data, 2015 emissions are 2% below the 2005 level.

3. The Federal Government's role

The Liberal government of Jean Chretien made an ambitious commitment under the Kyoto Protocol (signed in 1997 and solemnly ratified in 2002) to reduce Canada's total emissions 6% below the 1990 level by 2012. That would have required cuts to an annual total of 580 Mt. The Liberals left office in 2006. By 2005, Canada's total emissions were 738 Mt, rising to a peak of 750 Mt in 2007. The Conservative Government under Stephen Harper formally abandoned the Kyoto target. By then, the target was beyond reach.

Soon after it assumed power in 2006, the new Conservative government made a series of promises and declarations about how it would deal with carbon emissions. On April 25, 2007, Environment Minister John Baird made an extraordinary speech. "The climate is changing," he declared:

> *After 13 years of inaction by the Liberal government, <u>Canada is going in the wrong direction on the environment</u>. Since the Liberals promised to reduce greenhouse gases in 1997, they have only gone up. They promised to meet Kyoto, but went in the opposite direction … Now <u>we need to turn things around</u>. On*

> *behalf of all Canadians, particular our youngest citizens, we need to find a better way. Instead of greenhouse gases going up, we believe they should go down. Instead of putting more carbon in the air, we believe we should put less.*
>
> — speech, John Baird (emphasis added)

The text of John Baird's speech made on April 25, 2007 is not available on any Government of Canada site, but can be found on sqwalk.com: http://www.sqwalk.com/blog2007/001027.html#baird_globe

Baird announced a new climate action plan called *Turning the Corner*. It set a goal of reducing Canada's GHG emissions by 20% below 2006 levels by 2020, and a reduction of 60 to 70% below 2006 levels by 2050. The rising level of emissions from Alberta's expanding oil sands industry had become the largest source of emissions growth in the Canadian economy. Baird promised to develop regulations to address rising emissions in the oil sands industry.

In March 2008, the government unveiled proposed regulations explicitly aimed to curb CO_2 emissions from oil sands extraction and processing: see Environment Canada, March 10, 2008 (http://www.marketwired.com/press-release/government-delivers-details-of-greenhouse-gas-regulatory-framework-830605.htm) and *National Post*, March 11, 2008 (http://www.nationalpost.com/news/canada/pickton/baird+talks+tough+emitters/365981/story.html). The draft regulations, however, were never enacted.

The result is that over the past ten years (and currently) there has been no Federal Government regulatory control over the growth of oil sands emissions.

The Federal Government, however, has continued to make commitments to reduce Canada's total emissions. In December 2009, the Conservative government made a new commitment to achieve, by 2020, a 17% reduction below the 2005 level, which would be 613 Mt. The *Reference Case* now tells us that by 2020 total emissions will be about 731 Mt – less than 1% below the 2005 level.

4. Background about CCS technology

By the time Alberta announced its ambitious *Climate Change Strategy* in 2008, there was already advanced interest and enthusiastic backing for CCS technology among governments, international agencies, and industry. Here is a small selection of the many sources from that period:

A comprehensive study of CCS was published by the IPCC in 2005: see *Special Report on Carbon Dioxide Capture and Storage*. The study involved 100 lead authors and 25 contributing authors, all specialists. IPCC member governments, including Canada, formally approved the text of the Executive Summary in Montreal on September 22-24, 2005. The Executive Summary of the IPCC special report on CCS is available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf

Mark Jaccard, *Sustainable Fossil Fuels*, Cambridge University Press, 2005: a detailed examination of the prospects that CCS technology would allow the ongoing use of some amount of fossil fuels in a way compatible with a low carbon and ultimately a zero-carbon future. Chapter 6 specifically discusses CCS technology.

Andrew Nikiforuk, *Tar Sands: Dirty Oil and the Future of a Continent*, Greystone and David Suzuki Foundation, 2010: The author discussed CCS in chapter 9 and questioned both the economic viability and the long-term safety of using CCS in the oil sands.

Matthew Bromley et al., *Responsible Action? An assessment of Alberta's greenhouse gas policies*, Pembina Institute, December 2011: at pages 26-30 the authors discuss the prospects and impediments to adoption of CCS in the oil sands. https://www.pembina.org/reports/responsible-action.pdf

The 2013 edition of *Canada's Emissions Trends,* which is the Federal Government's annual review of emissions and climate policy, included a brief, non-committal reference to CCS in a two-page summary of "emerging technologies":

> *However, there are several emerging technologies that have the potential to further improve intensities through reductions in energy use or carbon capture and storage. Since the majority of new production is expected to occur at new facilities rather than at facility expansion, there is an opportunity to adopt these technologies when making choices on capital investments.*

— *Emissions Trends 2013* (underlining added)

In his 2010 book, *Ten Technologies to Save the Planet*, (Greystone), Chris Goodall provides a succinct and plain language review of CCS technology in the chapter titled "Capturing Carbon". Goodall believed at the time that worldwide commercial installation was unlikely till about 2028.

Goodall, an economist, has recently questioned whether CCS has any large future role in coal-fired electricity generation. In his new book, *The Switch* (Profile Books, 2016), he focuses on how the cost of solar power is falling much faster than anticipated, and now in many places in the world is approaching parity with the cost of electricity produced at existing coal plants. The implication is that as solar power becomes even cheaper over the next decade, producing electricity from coal plants equipped with expensive CCS will not prove competitive. See: "Is CCS really the answer?" *Carbon Commentary*, August 24, 2016, (https://www.carboncommentary.com/blog/2016/8/24/is-ccs-really-the-answer?rq=%20carbon%20capture%20and%20storage). Goodall examines the high cost of electricity produced at the new Boundary Dam plant in Saskatchewan, which started up in 2014. It is the first operating CCS-equipped coal-fired power plant in the world.

5. The International Energy Agency (IEA)

A report published by the IEA in June 2013, *Redrawing the Energy-Climate Map – World Energy Outlook Special Report*, includes a discussion of CCS at page 77-82. It examines proposed emissions-reduction policies under the IEA's 450 Scenario, aimed to keep global warming below the 2°C threshold: http://www.worldenergyoutlook.org/media/weowebsite/2013/energyclimatemap/RedrawingEnergyClimateMap.pdf.

In its 2013 report, the IEA urged that governments deploy CCS at large-scale CO_2 emitting sites, in particular at coal-fired electricity generating plants, starting by 2020. The report discusses the consequences if CCS were not available to be deployed at an early date. The alternative to massive adoption of CCS, if we are going to keep total emissions within the required limits, is to *expand renewables even faster than planned.* But the report warned that a more rapid transition to renewable energy could be more expensive, or impossible, in any short time frame, especially in some industries:

> *While the delayed availability of CCS can be compensated in the power sector by increasing investments in renewables and nuclear, albeit at higher costs, the fact that alternatives are not available to compensate for a shortfall of the deployment of CCS technologies in industry is a bigger challenge.*

— IEA, *Redrawing the Energy Climate Map*, p. 78 (emphasis added)

We were warned by the IEA that if CCS is not widely deployed by 2020, faster reductions in fossil fuel use will have to occur in the transportation sector to meet overall CO_2 reduction targets. Delays in deploying CCS will therefore accelerate the need to curb global oil consumption:

> *For oil producers, the effect of delaying CCS would be indirect: in order to keep cumulative CO_2 emissions the same in the absence of CCS, the transport sector would need to compensate by reducing emissions further through widespread deployment of electric vehicles.*

— IEA, p.80 (emphasis added)

Despite these warnings, it is now clear that large-scale global deployment of CCS is not going to happen by 2020, and may never happen on the scale originally envisioned.

In the U.S., the Kemper plant in Mississippi was supposed to have been the first CCS-equipped coal-fired electricity generating ("clean coal") plant in the country. But in June 2017, after enormous delays, technical problems, and some $7.5 billion in costs, it was announced that the plant will instead be fuelled by natural gas: see *Bloomberg*, Jim Polson, June 21, 2017, "First-of-Its-Kind Clean Coal Plant May Not Burn Coal at All" (https://www.bloomberg.com/news/articles/2017-06-21/a-first-of-its-kind-clean-coal-plant-may-end-up-burning-no-coal). Funding for a second U.S. "clean coal" project (FutureGen in Illinois) has been suspended. The problem is the monumental costs of building coal plants equipped with CCS, combined with the rapidly falling costs of renewable energy options – onshore wind power and solar photovoltaics (PV): see *Forbes*, May 3, 2017, Jeffery Rissman and Robbie Orvis of Energy Innovation, "Carbon Capture and Storage: An Expensive Option For Reducing U.S. CO_2 Emissions" (https://www.forbes.com/sites/energyinnovation/2017/05/03/carbon-capture-and-storage-an-expensive-option-for-reducing-u-s-co2-emissions/2/#329fb46215d5).

The future role for CCS technology has been dramatically downgraded in the IEA's most recent annual report, *World Energy Outlook 2017*, published on November 14, 2017. In 2011, the IEA projected that CCS would by 2035 account for 22% of all needed emissions reductions, while the shift to renewable energy would provide only 21% of the needed cuts. In the 2017 report, CCS is expected to account for only 9% of emissions cuts by 2040, while renewables account for 36%.

The expectation five years ago was that massive adoption of CCS would delay the need to shut down coal-fired facilities, allowing more time for a transition to renewable sources. But the continued high cost of CCS and the rapid fall of renewable energy prices has changed the outlook. In the case of China, with a very large coal-dependent power sector (and many of the plants still relatively new), CCS may still have an important role.

6. The abandonment of CCS in Alberta

The initial public indication that CCS had no future in the oil sands industry appeared in July 2014, but the media coverage at the time was muted. The articles cited below all touched on the economic viability of CCS, but none raised any questions about the future impact on Alberta's ability to reduce its emissions:

The Globe and Mail, "Prentice lets carbon capture go", Kelly Cryderman, July 18, 2014: http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/alberta-leadership-hopeful-prentice-lets-carbon-capture-go/article19668361/;

The *National Post* on October 6, 2014 reported a subsequent announcement by Prentice, after he became premier, confirming that decision. He is quoted as saying, "Prudence dictates that we should ensure that we begin to see some commercial viability to these investments": Geoffrey Morgan, http://business.financialpost.com/news/energy/jim-prentice-to-wind-down-carbon-capture-fund-in-alberta-new-projects-on-hold

Calgary Herald, June 13, 2015, James Wood. "NDP pledge to end carbon capture projects easier said than done" http://calgaryherald.com/news/politics/ndp-pledge-to-end-carbon-capture-projects-easier-said-than-done. The NDP platform for the May 5, 2015 provincial election in Alberta promised to end the government's "costly and ineffective carbon and capture storage experiment" and reinvest the funding in public transit. The Wildrose Party also opposed CCS. By 2015 there was no political support for CCS in Alberta as a technology to reduce emissions in the oil sands industry.

Report of the Auditor General of Alberta, July 2014, "Environment and Sustainable Resource Development – Climate Change Follow-up", at pp. 39-47: https://www.oag.ab.ca/webfiles/reports/AGJuly2014Report.pdf. This report was released about a week before Mr. Prentice made his announcement. It confirmed that Alberta's 2008 Plan would not meet any of the carbon reduction goals it originally set for 2020.

7. Technological Prospects Report (2015)

The Council of Canadian Academies published its report, *Technological Prospects for Reducing the Environmental Footprint of Canadian Oil Sands,* on May 28, 2015. The full report can be accessed at: http://www.scribd.com/doc/266900630/Technological-Prospects-for-Reducing-the-Environmental-Footprint-of-Canadian-Oil-Sands#scribd.

The panel examined the impact of oil sands development on the environment in five different ways: (i) GHG emissions; (ii) other air pollutants, including sulphur dioxide; (iii) water withdrawal (principally from the Athabasca River); (iv) the disposal of tailings ponds; and (v) physical land disturbances. In this essay, I refer only to the part of the report that deals with GHG emissions, which covers the three main processing activities in the oil sands industry – surface mining extraction, in situ extraction and upgrading.

8. Media and public discussion about CCS since 2015

Strangely, despite the abandonment of CCS in Alberta three years ago, recent reports in the mainstream media continue to portray CCS technology as something that will help solve the problem of rising oil sands emissions in Alberta (see, for example, *The Globe and Mail*, September 15, 2016, "First carbon-capture project in oil sands hits milestone", Ian Bickis: http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/first-carbon-capture-project-in-oil-sands-hits-milestone/article31881790/). The Bickis article gives a glowing report confirming that Shell Canada's Quest project had "successfully stored one million tonnes of carbon dioxide deep underground after a year of operation":

> *The development, and carbon capture operations in general, have been significantly criticized as high-cost, stop-gap measures that rely heavily on government funding.*
>
> *But Ms. Yujnovich* [a Shell Canada vice-president] *says <u>the technology provides an important bridge as part of a long-term transition towards renewable energy.</u>*
>
> *"The question for all of us is to say in the meantime, with the demand that still exists for oil products, 'How do we go about being as efficient as possible at extracting oil from the ground?'" she said.* (emphasis added)

What the article does not explain is that while the single installation at Shell's Scotford Upgrader removed and sequestered one million tonnes of CO_2 underground during the preceding year (and will repeat that feat in future years), since 2009 the overall level of oil sands emissions has been rising by *an additional 4 million tonnes (Mt) every year* – and further large annual increases are projected to continue until 2030 at least.

The Bickis article is silent about the fact that no additional CCS projects are scheduled, and does not mention that the Alberta government has dropped all funding support for the technology – although the article obliquely acknowledges the end of government funding by saying that "government appetite to fund the projects is waning." It does not mention the negative assessment by the *Technology Prospects* (2015) report: that CCS, because of its high cost, may never prove viable for any large-scale deployment in the oil sands – and that in any case it would not be economically viable for another ten or fifteen years. The article ends lyrically, with a description of the virtually unlimited space available to store CO_2 underground in the porous rock formations beneath the Prairies:

> *You could do another 20 Quests for the next 25 years just to fill up that zone, and this Basal Cambrian Sands goes all the way from northwest Alberta into Saskatchewan, and even touching Manitoba.*

Another article highlighting the prospects of CCS technology in the oil sands appeared in *The Globe and Mail*, on October 10, 2016: see Michael Crothers, "Why carbon capture is just as important as renewable energy": *https://beta.theglobeandmail.com/report-on-business/rob-commentary/why-carbon-capture-is-just-as-important-as-renewable-energy/article32311433/?ref=http://www.theglobeandmail.com&*

This is an opinion piece that extols the future of CCS as a solution to rising carbon emissions. Crothers is the President of Shell Canada, for many years one of the largest emitters in Alberta's oil sands. In this piece, he suggests that too much attention is being given to renewable energy. He refers, in particular, to the giant Desert Sunlight photovoltaic solar farm in California, the world's fourth largest solar installation of its kind. He notes that the emissions-free electricity generated at the California solar farm avoids 300,000 tonnes of CO_2 per year. He compares that to the much larger 1.0 million tonnes of CO_2 that Shell's CCS project is annually "storing away for good" underground in Alberta.

But the real difference between the two projects (not touched on by Crothers) is that the renewable solar electricity generated at the Desert Sunlight site in California, which saves 300,000 tonnes of CO_2 per year, generates *no other carbon emissions at all*. While it is true that Shell's CCS equipped-oil sands project in Alberta manages to "store away for good" 1.0 million tonnes of CO_2 per year, those emissions (captured during the processing phase at Shell's facility in Alberta) are only a small proportion of the total carbon emissions ultimately generated by the crude oil produced by Shell in Alberta. Once the product is exported from Alberta, and after it has undergone further processing at refineries in U.S., at the final stage of its "well-to-wheels" cycle (i.e., combustion in vehicle engines) that oil will release into the atmosphere *another* 4.0 million tonnes of CO_2, in addition to the 1.0 million tonnes "captured" at the processing stage. Generally speaking, about 80% of all emissions from crude oil occur during the final stage of combustion. The 1.0 Mt sequestered underground in Alberta at Shell's CCS equipped facility is just a fraction of the total.

Crothers also comments dismissively on the large land area that a solar energy facility would have to occupy to equal the carbon savings of the Quest project: it would cover "an area 16 times the size of Toronto Islands," he says. He ignores the hundreds of square kilometers of boreal forest in Northern Alberta now covered by an industrialized landscape. Surface mining operations disturb massive contiguous areas, encompassing the mining pits, tailing ponds, end-pit lakes, extraction plants, the storage of overburden, coke and sulphur stockpiles, and road networks. If you fly in a small plane out of Fort McMurray, you can circle an hour and a half in any direction and see nothing else to the horizon – except in situ well pads, seismic lines, access roads, pipelines, overhead power lines. Indigenous land users are excluded from the operational areas. Water sources are contaminated in many development zones.

After claiming that "the technology is good and it works", the Shell executive complains:

> *Yet, despite its promise, CCS seems to be the Cinderella of the world's energy transition. It is yet to be invited to the ball. Instead, attention is focused on renewable energy and efficiency measures.*

The truth is that CCS was "invited to the ball" in Alberta eight years ago, when CCS was given the leading role in *Alberta's 2008 Energy Strategy*. As we know, only two CCS projects were ever built. In the case of Shell's Quest installation, federal and provincial taxpayers generously paid $800 million out of the total $1.2 billion capital cost. But through all those years, while enjoying record high oil prices, the oil sands industry opposed any increase in Alberta's SGER levy – a derisory carbon price that until 2015 never exceeded 20 cents per barrel. Had the SGER levy been substantially increased in the years after 2008, it might have provided some economic incentive for the industry to make the huge capital investments needed to deploy CCS on a large scale. Instead, the industry did nothing to move CCS forward (and nor did the Alberta or the Federal Government).

9. Changes in emissions intensity

The *National Inventory Report* (April 13, 2017) confirms that carbon intensity per barrel in the oil sands declined by 26% between 1990 and 2005, remained largely unchanged from 2005 to 2010, and then declined again between 2010 and 2015 by 16%.

It is helpful to consider some of the circumstances that have delayed or impeded improvements in carbon intensity per barrel.

In *Canada's Emissions Trends 2013* (based on reported emissions data up to 2011), the government commented on what appeared then to be a prolonged period of "plateaued" improvements:

> *In recent years some <u>efficiency improvements have plateaued</u> as technological improvements have been negated by <u>shifts to more energy-intensive extraction techniques</u> and <u>declining reservoir quality</u>.*

— *Canada's Emissions Trends 2013*, p. 23

In the above quote, "shifts to more energy-intensive extraction techniques" refers to the fact that an increasingly large share of bitumen extraction was by then being done by underground in situ methods, which require substantially more gas-generated heat and steam to melt the bitumen embedded deep underground, compared to the traditional surface-mining methods. “Declining reservoir quality” tells us that as mining operations advance into *poorer-quality land formations* where the bitumen content is less easily separated, the quantity of natural gas required to generate sufficient heat and steam to extract each barrel of bitumen is increased. In those circumstances, carbon intensity per barrel rises.

The government’s *National Inventory Report*, published in April 2014, provided some additional commentary on factors affecting the trend of carbon intensity per barrel since 2004:

> *However, the emissions intensity of oil sands operations declined steadily until about 2004, due to technological innovations and equipment turnover, increased reliability across operations, and <u>the avoidance of upgrading emissions by exporting more crude bitumen</u>. The most significant factor contributing to this overall trend has been declining rates of emissions associated with fuel combustion. <u>Since 2004, the emissions intensity from oil sands operations has remained fairly static</u>.*

— *National Inventory Report* (2014), Executive Summary, page 6 (emphasis added)

Upgrading is an energy-intensive process after the initial extraction stage, where raw bitumen is further treated, converting it into synthetic crude oil, which is essentially a semi-refined product. The upgrading process adds to the amount of emissions per barrel. When Alberta producers began to ship a larger proportion of total bitumen production out of the province without upgrading, average emissions per barrel declined. The upgrading emissions would instead be generated at refineries in the U.S. (or in other foreign jurisdictions), but not in Canada.

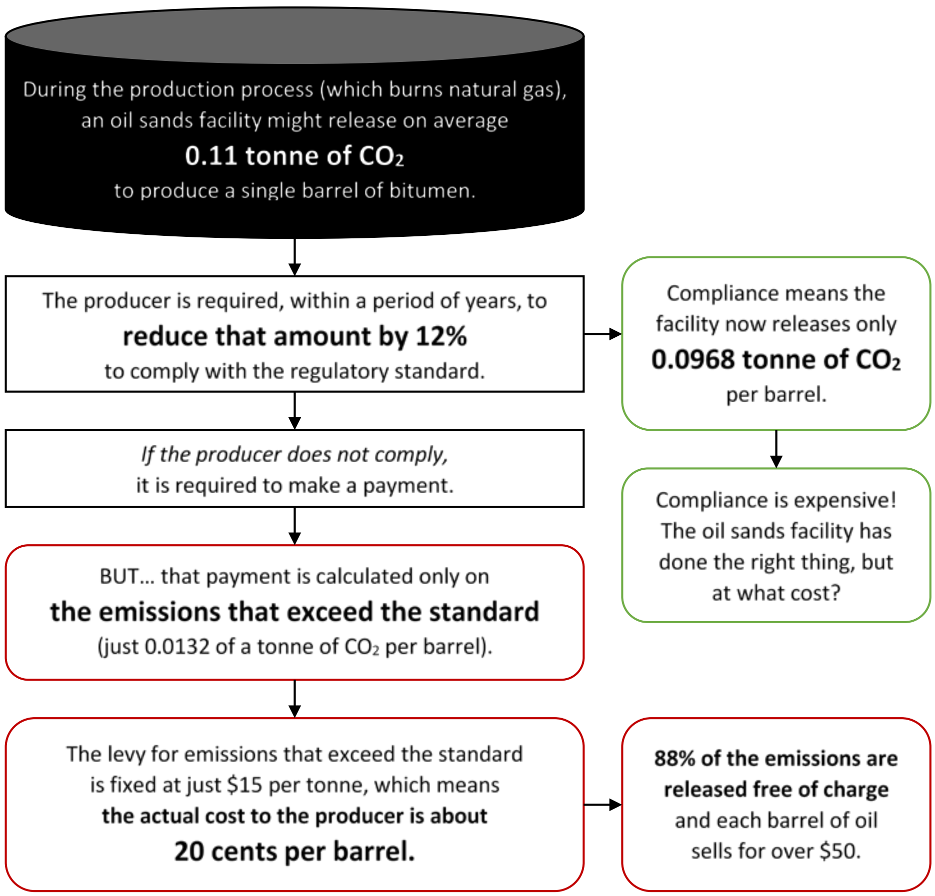
10. Ten lost years: Alberta’s inadequate SGER

A comprehensive study published by the Pembina Institute in December 2011 explained how the SGER worked, and why it was having little impact on reducing oil sands emissions: see *Responsible Action? An Assessment of Alberta’s Greenhouse Gas Policies*, Matthew Bramley, Marc Huot, Simon Dyer, Matt Horne (http://www.pembina.org/reports/responsible-action.pdf).

For the purpose of illustrating the economic impact of the SGER on producers, the Pembina Institute study assumed that during the production process (which burns natural gas) an oil sands facility might release on average a total of 0.11 tonne of CO_2 to produce a single barrel of bitumen. That was a realistic measure of carbon intensity per barrel in 2011 (equivalent to 110 kg); the average today is 79 kg of CO_2 per barrel.

Under the SGER scheme (as it operated up to January 2017), the producer was required, over a period of six years, to reduce that amount by 12% in order to comply with the regulatory standard. *If the producer did not comply at all* (taking no steps to lower carbon emissions intensity within the required period) it would be required to make a payment, in that example, calculated solely on the 12% of the emissions that exceeds the standard, which in that case would amount to only .013 of a tonne of CO_2 (12% of 0.11 tonnes of CO_2).

I have prepared this informal graphic to summarize the way the scheme worked:



A representation of the SGER scheme in Alberta as it operated from 2008 to 2016.

Based on a levy fixed at $15 per tonne, the actual cost to the producer was about 20 cents – 20 cents per barrel. That is how the SGER was designed.

Put another way, under the SGER scheme, 88% of the emissions were released free of charge. The so-called “carbon price” only applies to the fractional share of emissions that exceeds the performance standard – in this case, the 12% of emissions that were supposed to be cut from the production process over a period of years.

Failure to reform the SGER scheme: 2013-2014

In 2013 the governments of Alberta and Canada, with representatives of the oil sands industry, engaged in closed-door negotiations about possible modifications to Alberta’s SGER. The Alberta government, by then headed by Premier Alison Redford, announced its “40-40 proposal” which would have required that producers reduce their emissions intensity by 40% over a specified period of time (instead of the existing 12% reduction of emissions intensity). The proposal would have increased the penalty for non-compliance to $40 per tonne of CO_2, up from $15.

The industry responded with a counter-proposal: it took the position that emissions reduction should be fixed at 20%, and that the payment should be increased no higher than $20 per tonne of CO_2 (that was the industry’s “20-20 proposal”).

For a discussion of the negotiating position of the Canadian Association of Petroleum Producers (CAPP), see the Pembina Institute, Simon Dyer, November 8, 2013 (http://www.pembina.org/blog/762). Documents obtained under Alberta’s Freedom of Information legislation showed that CAPP, on behalf of oil sands producers, argued that incurring additional costs to adopt technology to reduce emissions would discourage new capital investment in the oil sands. At that time, world oil prices were up in the range of US$100 to $110 per barrel (the big price collapse did not begin until July 2014). An analysis published in April 2014 by the Pembina Institute showed that under the Alberta government’s proposed 40-40 plan, the average cost to comply per barrel would increase to about $1.50. After taking into account the deduction of royalties and tax treatment, the effective cost would be less than that.

One of the CAPP documents, entitled “Concerns and Questions for Alberta and Consultants”, prepared by a senior CAPP official, summarized the industry’s grounds for opposing the Alberta government’s 40-40 proposal. Most significantly, CAPP rejected the Alberta government’s view that a higher carbon levy would induce producers to adopt technology that would reduce carbon emissions:

> *Will higher stringency requirements deliver greater GHG reductions? Unlikely. The challenge with the oil sands is that <u>current technology is not yet available for deployment</u> to a significant degree.*
>
> — CAPP documents, see https://www.desmog.ca/2013/11/11/objection-oil-sands-ideological-says-industry-resisting-new-emissions-standards (emphasis added)

CAPP’s claim that suitable technology was *not available* is striking. If accurate, that claim undermines expectations that a more stringent SGER penalty (or a more stringent carbon price of any kind) could lead to lower carbon emission per barrel. If the technology is not available, there will be no carbon intensity improvements – no matter how stringent the tax.

CAPP further countered that “higher stringency requirements” (e.g., a higher price on carbon emissions) would slow down the growth of oil sands production:

> *Will higher stringency requirements impact production and revenue? Very likely. Adding a regressive charge to the oil sands, one that bites harder at low prices than high prices, introduces additional cost and risk. <u>This will impair recovery of marginal resources</u> associated with existing projects. And make new projects less*

> *competitive from a portfolio perspective. And the higher costs associated with additional stringency can also impair the resources devoted to research.*

"Marginal resources" are *poorer quality bitumen deposits where more heat and steam is needed to extract the same amount of bitumen*, compared to working the richest bitumen deposits. If there is a substantial carbon price charged on emissions, "marginal resources" (which will require the release of more CO_2 for each barrel extracted) will become less profitable, or perhaps completely unprofitable, to extract. A higher carbon price would make it problematical for the industry to expand production of lower-grade, more emissions-intensive, bitumen deposits.

By early 2014, the Alberta government had dropped its 40-40 plan.

The collapse of global oil prices

In July 2014, Jim Prentice, then campaigning to become leader of Alberta's governing Conservative Party, promised he would *not proceed with any increase* in the amount of the levy under the existing SGER scheme, unless that could be done jointly with the United States. Given the deadlock in domestic American politics on climate policy, waiting until a common carbon tax on oil production could be negotiated with the United States would mean the SGER levy in Alberta would be frozen at its existing nominal level, possibly for many years.

When, in mid-2014, Jim Prentice promised that he would reject any increase in the carbon price, oil was trading above US$90 a barrel. By early summer 2015, the price was down to around US$45. The costs of production per barrel in the Alberta oil sands are among the highest in the world due to the energy intensive extraction process and the massive capital cost of the facilities.

Following a provincial election in May 2015, a majority NDP government was elected in Alberta.

By mid-2015, however, the options for dealing with the SGER were severely constrained, politically and economically, by the collapse in world oil prices. By mid-2015 oil prices had declined uncomfortably close to the cost of production per barrel at some oil sands operations. Companies were desperately cutting capital investment budgets, laying-off employees, and attempting to reduce production costs. It was not a good time to see any significant increase in the SGER carbon price, which would add to the cost per barrel.

On June 25, 2015, Shannon Phillips, Environment Minister in Alberta's new government, announced an increase in the carbon levy from its current $15 to $20 on January 1, 2016, and a further increase to $30, effective January 1, 2017. An increase in the performance standard was also announced, stipulating that after January 1, 2017, producers would be obliged to reduce their facilities' carbon intensity by 20% (up from 12%). The amended scheme did not differ very much from the "20-20 plan" offered by the oil sands industry in 2013. The effective cost per barrel would rise from 20 cents to about 60 cents. It was a minimal increase. It was not scheduled to fully come into effect until 2017.

Then, on November 20, 2015, the Alberta government announced that, effective in 2018, the SGER scheme would be replaced by the new Carbon Competitive Regulation (CCR): see Note 12.

11. Alberta's Climate Leadership Plan (2015)

On August 14, 2015, the province's new Environment Minister announced the appointment of a five-member Climate Change Advisory Panel, which was chaired by University of Alberta economist Andrew Leach. Simultaneously, the government issued what it called the *Climate Leadership Discussion Document*: http://www.alberta.ca/albertacode/images/Climate-Leadership-Discussion-Document.pdf

The *Discussion Document* contains a surprisingly candid summary of the dilemmas facing the newly elected Alberta government: the steady rise of emissions in the oil sand sands; the collapse of Alberta CCS strategy; the Federal Government's promise (announced by the Harper Government on May 30, 2015) to achieve a 30% absolute reduction of Canada's total emissions by 2030; the fact that Alberta contributes 37% of Canada's total emissions (based on the 2014 figures); and the projection that the province's proportionate share of Canada's total emissions will continue to rise to 2030. The paper also cited evidence of developing resistance in foreign markets to fuel products that fail to meet carbon intensity standards, citing the case of California:

> *For example, California's Low-Carbon Fuel Standard calls for a reduction of at least 10% in carbon intensity of transportation fuels by 2020, meaning fuels made from crude sources with emissions-intensive production methods will be at a disadvantage in one of North America's target transportation fuel markets.*

— *Discussion Document*, p. 13 (emphasis added)

The paper contained a blunt critique of the existing SGER approach. Addressing the scheme's "intensity-based tools", the *Discussion Document* comments:

> *The current requirements ask these large industries to reduce their emissions intensity by 12% below a historical baseline. This means that each facility can continue to emit most of its emissions (88% per of its emissions intensity).*

— *Discussion Document*, p. 10 (emphasis added)

It acknowledges that, calculating the average carbon price under the existing scheme in Alberta, the levy is $1.80 per tonne of CO_2:

> *In Alberta, the average price for carbon for a regulated facility is the total cost of policy per total unit of emissions. A facility that has had constant emissions and production since the baseline will have an average cost of up $1.80/ tonne (12% of emissions at $15). This will increase to $6.00 by 2017 by 2017 (20% at $30).*

— *Discussion Document*, p. 17

Those amounts are equivalent to about 20 cents per barrel under the arrangement in place since 2007, and rise to 60 cents per barrel after the amendments made earlier in 2015 that take effect in 2017.

The Alberta government released a new Climate Leadership Plan on November 20, 2015. A 90-page report, entitled *Climate Leadership: Report to Minister*, was produced by the Advisory Panel chaired by economist Andrew Leach. It can be accessed at: http://www.alberta.ca/documents/climate/climate-leadership-report-to-minister.pdf.

The November 20, 2015 report candidly discusses the failure of *Alberta's 2008 Climate Change Strategy*. It concludes that the 2008 plan's ambitious target that oil sands emissions would begin to decline by 2020 was never supported by sufficiently stringent carbon prices and regulations to achieve the promised results:

> *… these targets were based on a computer model under the assumption that Alberta's policies would include "… a strict regulation that all large, new industrial facilities are required to incorporate carbon capture and storage by 2015 wherever possible". The latter of those assumptions, a requirement to adopt carbon capture and storage in industrial facilities, was supposed to have led to the lion's share of reductions posited in the target by 2050 but neither these regulations nor the modeled carbon price were imposed.*

— *Climate Leadership,* November 20, 2015, p. 25 (emphasis added)

The deep emissions reductions promised by Alberta's 2008 plan were based on the assumption that the government would enact a mandatory regulation requiring oil sands producers to *incorporate carbon capture and storage by 2015*. But no mandatory regulation was ever adopted. Alberta's Auditor General had warned – in an October 2008 report – that the necessary regulation had not been put in place (http://www.oag.ab.ca/webfiles/reports/Oct_2008_Report.pdf: see "Alberta's response to climate change", in particular pp. 98-99).

12. Carbon Competitive Regulation (CCR)

In the case of the oil sands industry, Alberta's 2015 plan recommended a new Carbon Competitive Regulation (CCR) to replace the SGER, starting in 2018. To begin, it will be based on a carbon price of $30 per tonne (the same as the recently proposed price increase under the SGER). The report proposed that, after 2018, the carbon price should continue to increase, but subject to this condition:

> *However we recommend that government commit to increasing that price by 2% per year above inflation so long as [carbon] prices increase in comparable jurisdictions (including jurisdictions which host competitors to our resource production), to match Alberta's prices."*

— *Climate Leadership*, page 37

The new plan is aimed at inducing oil sands producers to invest in new technologies that will lower emissions per barrel at their operating sites. Under the new plan, all facilities will be allocated (at no cost) a share of "emissions rights" (i.e., a permit allowing each company to release a specified quantity of emissions into the atmosphere free of charge). But the amount of emissions rights will be based on *"top quartile performance in in situ and mined production of bitumen"* – meaning that while each individual facility will receive an *"output-based allocation"* (taking into account the actual number of barrels produced at that site), the quantity of emissions rights issued to each company will be calculated as if it is achieving the same low carbon intensity per barrel as the most efficient producers.

Therefore, under the new plan, the amount of emissions rights allocated to any particular producer will give a financial advantage to companies that achieve the *lowest carbon emissions per barrel* in their own operations. In effect, the most efficient companies will receive enough emissions rights to cover the entirety of their output (and if they are very highly carbon efficient, they will have surplus permits left over that they can sell). Other producers, who operate facilities that generate much higher levels of CO_2 per barrel, will be obliged to pay the carbon price (set at $30 per tonne) on all emissions that exceed their allocated share.

The result is that *"less advanced, older, or more emissions-intensive processes will be disadvantaged, as will operations in challenging conditions"*: i.e., companies extracting poorer quality resources that require higher levels of fuel to extract each barrel (and which are therefore more emissions intensive per barrel) will pay more.

The panel also recommended that the total allocation of emissions rights be decreased by 1-2% per year, which would put further pressure on all producers to continue to lower their emissions. However, that recommendation is subject to the same caveat that "competitor jurisdictions" adopt equivalent increases in the stringency of their own carbon reduction policies.

Oil sands producers will still be under no legal obligation to reduce carbon intensity at all, or to curtail the growth of their emissions. If a producer decides not to meet (or cannot meet) the performance standard under the new CCR, it will have the option to simply pay the financial penalty.

13. Alberta's emissions growth to 2030

It is true that Alberta's Climate Leadership Plan announced in November 2015 promises some major improvements. A $30 per tonne carbon tax in Alberta is now applied to 90% of the province's emissions, including to transportation fuel prices for vehicles and household heating bills. The province will also phase out all coal-fired electricity generation by 2030. That transition away from coal-based electricity will reduce the province's emissions by at least 14 Mt below the current projection, and possibly more, depending on the share of renewables used to replace the coal-fired plants. If renewables provide a high proportion of the replacement power (the alternative is expanded reliance on natural gas), the emissions reduction will be more than 14 Mt.

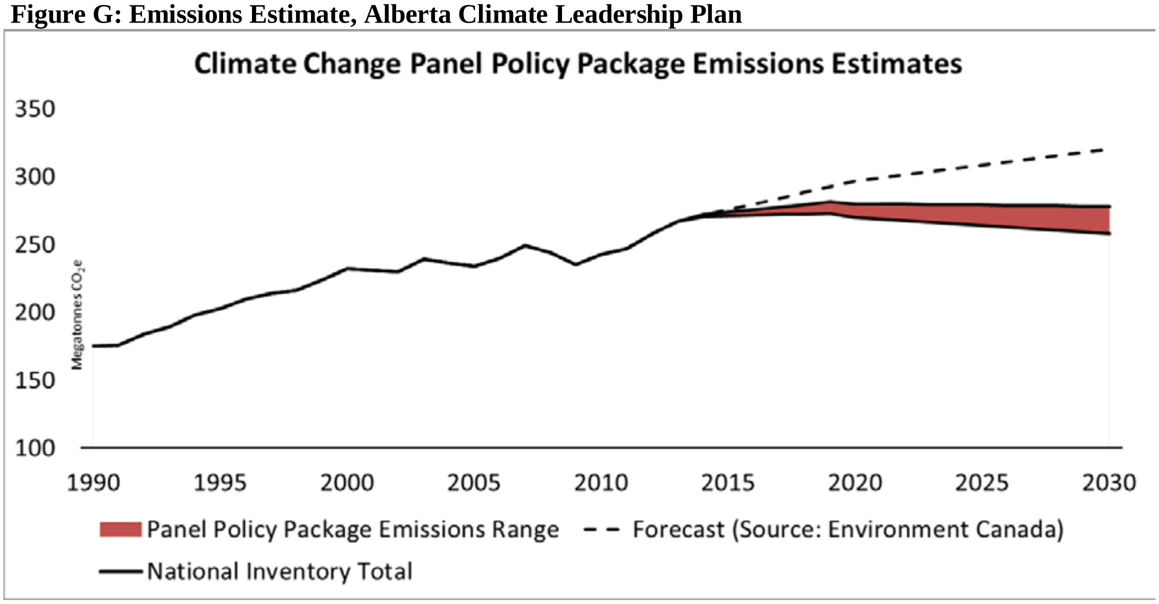
Under the new plan, in the oil and gas sector the largest share of proposed emissions reductions relate to methane, which comprises a significant proportion of the total GHG emissions in that sector (particularly in natural gas production and processing). The plan estimates that the annual level of methane emissions in Alberta can be reduced in the range of 7-17 Mt CO_2eq by 2030. It adopts 12 Mt as an achievable methane reduction goal (pp. 63-65). The report summarizes the combined effect of the proposed methane regulations and the new CCR:

> *When combined with our carbon pricing program applied in oil and gas, we expect a total of approximately … 20 Mt of annual emissions reductions by 2030 over and above what otherwise occur with a continuation of the Specified Gas Emitters Regulations as implemented today.*
>
> — *Climate Leadership*, p. 65

Therefore, Alberta's plan promises a total 20 Mt reduction in the province's oil and gas emissions by 2030, below the forecast growth. About 12 Mt of the promised cuts, if they materialize, will be methane reductions. The remaining 8 Mt will be achieved by the new carbon price scheme (the CCR), which is expected to modestly slow down on the rate of increase of oil sands emissions.

According to the *Climate Leadership Report*, by 2030 all of these new initiatives in Alberta are expected to reduce Alberta's total annual emissions by 50 Mt below the currently projected level – from 320 Mt down to about 270 Mt. The outcome is depicted in this graph, which was published in the Alberta document:

Figure G: Emissions Estimate, Alberta Climate Leadership Plan



Source: *Climate Leadership Plan: Report to Minister*, November 20, 2015.

We can see, however, that despite the promised new measures, by 2030 Alberta's total emissions will be more or less the same as they are today. The problem is that most of

Alberta's promised reductions after 2020 will be offset by the increase of oil sands emissions between 2014 and 2030.

Figure H reproduces the Government of Canada's projections for Alberta's total emissions up to 2030, published in the *Reference Case* (December 2016). According to that report, these numbers "incorporate the expected impacts of … provincial policies" put in place over the past year, including "Alberta's Carbon levy, 2030 phase-out of coal-fired electricity, and 100 Mt cap on oil sands emissions": see *Reference Case*, Introduction, p.2. These numbers do not include the impact of promised methane reductions, because the methane regulations have not yet been finalized.[§]

Figure H: Province of Alberta – emissions projections to 2020 and 2030 (Mt CO_2eq)

	2005	**2014**	**2020**	**2030**
Alberta	233	274	276	279

Source: *Canada's Greenhouse Gas Reference Case*, Environment and Climate Change Canada (December 2016), Table A24.

Under the new plan, by 2030 Alberta's emissions will still be well above the 2005 level. Our national commitment is that Canada's total emissions will be 30% below the 2005 level by 2030. Alberta will contribute nothing to that. Even if Alberta successfully implements all of its proposed new policies, the burden of making deep cuts below the 2005 level will still fall entirely on the other provinces, and almost all of the needed reductions will have to come from non-oil and gas sectors.

Alberta' *Climate Leadership Report* concedes that despite the new carbon pricing regulations that apply to oil sands producers, total oil and gas sector emissions will continue to rise to 2030:

> *This would still imply substantial expected growth in oil and gas emissions, to 55% above 2005 levels by 2030 …*
>
> — *Climate Leadership, Report to Minister*, "Emissions Reductions", p. 65

The Federal Government's most recent emissions projections (*Reference Case*, December 22, 2016) provide a substantially identical forecast: total oil and gas sector emissions are expected to increase from 159 Mt in 2005 to 233 Mt by 2030 – which is an absolute increase of 46%. The oil sands industry accounts for virtually all of the 74 Mt increase: see Figure E at p.17.

[§] If we accept 12 Mt of potential methane reductions given by the *Climate Leadership Report* as a mid-range estimate of what can be achieved, Alberta's total emissions could be reduced to around 265 Mt by 2030. Methane emissions in 2014 from all sources in Canada were 108 Mt CO_2eq (representing about 13% of all emissions in Canada), of which 48 Mt was generated by the oil and gas sector, mostly in Alberta and B.C., mainly from natural gas extraction and processing activities: see *Reference Case*, Table A18. The promised policy goal in Canada is a 45% reduction of oil and gas sector methane emissions by 2030, which if fully achieved would amount to a 20-25 Mt cut.

14. Carbon leakage

The Alberta panel conceded that all of these new measures will have only limited impact, when considered in the context of the commitments made by Canada under the Paris Climate Agreement Treaty, in December 2015:

> *Many will look at these emissions reductions and claim that our policies will not place Alberta on a trajectory consistent with global 2° goals, and in some sense this is true – the policies proposed for Alberta in this document would not, if applied in all jurisdictions in the world, lead to global goals being accomplished.*

The Climate Leadership report concluded that more aggressive policies to substantially reduce oil sands emissions are "not tenable", because they would raise production costs for Alberta producers and make the industry uncompetitive against lower-cost oil production in other jurisdictions:

> *However, more stringent policies in Alberta would come at significant cost to the province due to lost competitiveness, with negligible impaction on global emissions due to carbon leakage. As a panel, we have looked at this challenge and concluded that while we do not have an architecture that, in the short-term, will be consistent with meeting global goals, the approach we are proposing will position Alberta to make a meaningful contribution in the longer-term. In the meantime, imposing policies in Alberta that are more stringent than what we have suggested is not tenable, until our peers and competitor jurisdictions adopt policies that would have a comparable impact on their industrial sectors.*

— *Report to Minister,* "Outcomes and Impacts", p. 11 (emphasis added)

"Carbon leakage" means that if Alberta were to adopt more stringent policies aimed to eliminate or substantially cut the projected growth of oil sands emissions, the additional costs (incurred by producers to adopt required new technologies to lower emissions per barrel) would make Alberta's bitumen production more expensive, and therefore uncompetitive. Alberta's production and exports would as a result decline – but crude oil producers in the U.S., or in Saudi Arabia or elsewhere, would increase their output.

The choice for Alberta is to pursue the economic benefits of continued expansion of its oil sands output, or, in the alternative, adopt more stringent carbon prices and tougher performance standards that would achieve deeper reductions in emissions per barrel – but it cannot do both, according to the panel.

That is the dilemma. The Alberta panel recommended the path of continued expansion. Imposing more stringent emissions reduction in the oil sands will result in "sacrificing wealth and prosperity" in Canada (i.e., lower production levels) while other countries increase their output to replace our exports.

15. Solvent-assisted technology

Canada's Energy Future 2017 (October 17, 2017) considers the potential impact of new technologies on Canada's future energy supply and energy use. In the case of the oil sands industry, the only new technology chosen for discussion is solvent-assisted technology described as "one technology that has potential to reduce in situ supply costs, natural gas consumption, and GHG emissions". The report acknowledges that the cost-effectiveness of solvent processes is uncertain, identifying the same cost issues as the *Technological Prospects* study. The NEB is non-committal about whether the technology will be widely adopted, or when that might occur, but offers this hypothetical scenario:

> *The Technology Case assumes that oil sands producers increasingly use steam-solvent processes. Early in the projection period, the technology is applied at select extension projects and is gradually implemented at existing facilities later in the projection period.* (p. 66)

The "projection period" in this report is 2018 to 2040, so in this scenario any large-scale implementation is delayed until some time later in the next decade or after 2030. Canada's emissions reduction commitments promise deep cuts by 2030.

16. Oil sands production: forecast expansion 2014-2040

The economic foundation for the continued expansion of Canada's oil sands production is explained in a report published by the National Energy Board (NEB) on January 27, 2016, *Canada's Energy Future 2016*: *Energy Supply and Demand Projections to 2040.* The NEB concluded that global oil consumption, especially in Asia, will likely continue to grow for at least another twenty-five years. Based on that projection of increasing oil demand worldwide for several more decades, the NEB forecast that Canada's oil sands production would increase from the 2014 level of 2.4 million bpd to 4.8 million bpd by 2040 – a doubling of production.

In October 2016, the NEB published an update (titled *Canada's Energy Future 2016 Update*) that lowered the NEB's projections due to uncertainty about future oil prices. The *Update* forecast that oil sands production would reach 4.3 million bpd (instead of 4.8) by 2040, which is nevertheless a 72% increase above the 2015 level of 2.5 million bpd. Taking into account an additional 1.4 million bpd of conventional oil production, the *Update* projected that Canada's total crude oil output would reach 5.7 million bpd by 2040, up from 4.0 million bpd in 2015. The October 2016 *Update* report estimated that oil sand production would reach 3.967 million bpd by 2030: see Figure C at page 14.

On October 2017, the NEB released a new set of oil supply and demand projections, *Canada's Energy Future 2017*. Oil sands production is now expected to grow a little more robustly, reaching 4.5 million bpd by 2040. The new forecast expects output will reach 4.180 million bpd by 2030, an additional 215,000 bpd above the *Update* figure. That means oil sands emissions by 2030 will likely be somewhat higher than shown in the *Reference Case*. By 2040, Canada's total crude oil output, including 1.8 million bpd of conventional oil, is projected to reach 6.3 million bpd.

It is useful to look at Canada's oil sands growth in the context of global oil supply.

Between 2014 and 2040, according to the IEA's New Policies Scenario, total oil consumption worldwide is expected to increase from 90.6 million bpd to 103.5 million bpd (*World Energy Outlook 2015*). Canada currently contributes less than 5% of total global production. But our role as an oil supplier will become more crucial if the global appetite for oil continues to grow in line with the IEA's projections. Canada's *net increase of oil production* between 2014 and 2040 (which in 2015 the IEA projected as 2.3 million bpd) would be the third largest in the world, after Iraq (4.5 million) and Brazil (3.0 million). According to the IEA, six major oil producing countries have large enough oil reserves to substantially increase their own production levels over that period – the other three are Iran (1.9 million), Saudi Arabia (1.8 million) and Venezuela (1.1 million): see *World Energy Outlook 2015*, Chapter 3, Tables 3.6, 3.7, and 3.12.

In the IEA's *World Energy Outlook 2017*, published on November 14, 2017, the global oil supply under the New Policies Scenario rises to 104.9 million bpd by 2040. The U.S. is now expected, in the 2016-2040 period, to increase its output by 2.4 million bpd, joining the group of top suppliers. In that period, Brazil's production is now projected to rise by 2.6 million bpd, Iraq by 2.5 million bpd, and Canada by 1.7 million bpd.

We note that the IEA New Policies Scenario and the NEB estimates are both business-as-usual (or "baseline") projections – meaning they calculate the expected future path of global oil consumption on the assumption that no significant new carbon reduction policies (measures designed to curtail the future use of crude oil) are going to be adopted by the world's major industrial economies over the next twenty-five years, beyond existing measures already in place. The IEA's New Policies Scenario represents the expected trend of crude oil consumption assuming there is *no major shift away* from the internal combustion engine in transportation. It is a pessimistic scenario, from the perspective of curbing the future growth of CO_2 emissions. The IEA has repeatedly warned that the New Policies Scenario is not compatible with a 2°C world.

In comparison, the IEA's "450 Scenario" is a mitigation scenario. It is based on the assumption that countries will soon adopt carbon-reduction policies that will achieve significant reductions of global oil consumption – absolute reductions starting by 2020 – that are large enough to bring about gradually declining GHG emissions from the energy sector consistent with the goal of limiting the long-term rise of average global temperature to 2°C. The 450 Scenario concludes that in order to meet the 2°C goal, global oil consumption, which is projected to rise from 90.6 million bpd in 2014 to 93.7 million bpd by 2020, must then begin to decline, down to 74.1 million bpd by 2040. One of the questions we are left with is whether Canada's ambition to continue expanding oil sands production up to 2040 is consistent with a 2°C world.

17. The 100 Mt cap

Media discussion and political leaders frequently claim that oil sands emissions are going to be curbed or constrained because the Province of Alberta has imposed a 100 Mt cap on the total annual level of oil sands emissions. The suggestion is that this "cap" will help

Canada meet its emissions reduction target by 2030. But unfortunately, the "cap" is set so high – an upper limit of 100 Mt – that it will have no impact at all on limiting the growth of oil sands emissions before 2030. A note in *Canada's 2016 Greenhouse Gas Reference Case* explains that the 100 Mt cap, although it has been adopted by legislation in Alberta, will in fact do nothing to curb the rise of oil sands emissions up to the currently projected annual level of 108 Mt by 2030:

> *Based on the Alberta Government's announcement, Alberta's 100 Mt cap on oil sands emissions excludes emissions from cogeneration of electricity and new upgrading. When taking these into account, total emissions from oil sands is 93 Mt in 2030 under the reference case scenario, below the 100 Mt cap.*
>
> — *Reference Case*, section 2 "Emissions projections by sector", note 4, p. 7

Although it is not commonly understood, the 100 Mt cap does not apply to, or restrict, the growth of, *additional emissions* generated by the expansion of "new upgrading" in Alberta. Upgrading is a highly emission-intensive process that converts raw bitumen into a higher-value crude oil before it is shipped to foreign refineries for further processing. The cap also exempts additional emissions attributed to cogeneration. Therefore, under this scheme, total oil sands emissions (including upgrading and cogeneration) will be allowed to rise to about 115 Mt, or somewhat higher than that, before they exceed the cap. The projected 108 Mt of oil sands emissions shown in the Government of Canada's *Reference Case* (Figure C, at p. 11) is in fact *within the cap limit*, and represents only 93 Mt of oil sands emissions as defined by the cap.

The cap will not stop the annual level of oil sands emissions from rising another 40 Mt between 2014 and 2030.

18. Commitments to reduce Canada's total GHG emissions

Canada has agreed that we will reduce our total emissions (that is, *all* emissions caused by activities within our borders) 30% below the 2005 level, by 2030. That pledge was formally made by the Conservative Government on May 15, 2015, and was re-affirmed by the Liberal Government at the climate conference in Paris in December 2015. The 2005 level was 747 Mt. The target is 523 Mt (the red dot shown on Figure F at p. 21).

The magnitude of the challenge is evident if we look at Figure D on page 19.

Total emissions for all economic sectors are expected to reach 731 Mt by 2020. To meet our commitment by 2030, cuts of over 200 Mt would have to be achieved over ten years. One problem is that our biggest source of emissions, the oil and gas sector, will be unable to contribute any share of the needed reductions – because it will still be increasing – from 201 Mt to 233 Mt over the next decade (that increase could be about 20 Mt less if promised methane regulations are enacted and fully implemented across Canada). The *Reference Case* shows that two of the other sectors, agriculture and waste (which together will account for 123 Mt by 2020), will not be capable of providing any cuts at all over the next decade. That means the remaining four sectors (transportation, buildings, industry, and electricity), accounting for about 400 Mt of Canada's total emissions by 2020, will have to cut their combined emissions by 200 Mt within the decade, a 50% cut within ten years – if we are going to meet the target.

19. Misleading Language

Alberta's premier delivered a major speech on October 2, 2015, to a business audience in Toronto at the Empire Club. She said nothing about emissions reductions. She limited herself to vague language about "sustainable" development of energy resources:

> *It is my hope that by acting decisively on the issue of climate change, we will <u>reframe the current national debate</u> over pipelines and energy infrastructure. By making better decisions in Alberta about the environment, we will hopefully then be able to discuss key pipeline projects on their own economic and environmental merits.*

— speech, Rachel Notley (emphasis added)
(*http://alberta.ca/release.cfm?xID=386189FEB32C7-CB72-0AD5-105A19C6F9211E38*)

In remarks to reporters after her speech, Premier Notley went further, touching on the subject of emissions. *The Globe and Mail* published this account of the claim she made:

> *Technological advances, she said, can help companies produce petroleum from the oil sands with fewer emissions.*

— *The Globe and Mail*, October 3, 2015

In answer to Notley's claim, the Canadian Association of Petroleum producers (CAPP) was blunt and candid:

> *Jeff Gaulin, a vice-president of the Canadian Association of Petroleum Producers, said companies can reduce the amount of carbon they use to produce a barrel of oil sands oil. <u>But expanding production would still mean more overall emissions</u>.*
>
> *"Our industry can grow substantially over the coming years and, on a per-barrel basis, be the same or better than other barrels around the world," he said in an interview. "But at the end of the day, <u>by growing our energy sector, we will grow emissions</u>."*

— *The Globe and Mail*, Adrian Morrow, October 3, 2015 (emphasis added)

The industry association is right, on that point. The evidence supports the conclusion that if we continue to expand oil sands production over the next fifteen years, we will continue to see rising emissions in that industry in absolute terms.