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Les enjeux de la filière uranifère au Québec
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ROBERT F. MCCULLOUGH, JR.
PRINCIPAL

Uranium Mining in Quebec: Four Conclusions

Submission to the Bureau d'audiences publiques sur l'environnement

Robert McCullough
Rose Anderson
Ramon Cabauatan

EXECUTIVE SUMMARY

Uranium has proven to be a controversial topic in Quebec. In 2012, Strateco proposed a uranium mining project at its Matoush site in the Otish Mountains. In 2013, the Quebec Minister of the Environment mandated the Bureau d'audiences publiques sur l'environnement (BAPE) to undertake an inquiry and public consultation concerning the uranium sector in Quebec.

The BAPE's mandate raises a number of significant questions about the need for uranium, the future economics of the industry, the viability of uranium projects in Quebec, the appropriate level of remediation and surveillance, and past experience with uranium mines in Canada and other countries. This position paper summarizes extensive research performed by McCullough Research[1] on behalf of the Grand Council of the Crees (Eeyou Istchee) (GCC) and submitted to the Bureau d'audiences publiques sur l'environnment (BAPE).

The primary conclusions of our research are:

First, there will be a lasting oversupply of uranium for the foreseeable future. Shifts in the nuclear industry, accentuated by the falling price for natural gas and the arrival of three new "mega" mining projects, have reduced the long term price of uranium ore to very low levels. Existing forecasts of uranium prices tend to disregard reductions in dependence on nuclear energy in France, Germany, and Japan and assume that the ongoing decommissioning of nuclear plants will suddenly halt in the near future.

[1] McCullough Research's expertise and experience is summarized in Appendix A.

Second, at these low price levels, small-scale uranium mining is unlikely to be competitive for many years to come. Currently proposed projects in Quebec are not capable of competing with larger, richer, and better located projects in Saskatchewan, Australia, and Namibia.

Third, the environmental consequences of uranium mining can be severe, especially if careful remediation planning and remediation funding are not implemented. The experience in Canada and elsewhere indicates that it is difficult to predict the full cost of remediation. In addition, the industry has seen frequent cases where the original remediation measures have proven to be insufficient years after the project has closed.

Finally, the nature of long-term remediation requires active yearly surveillance for many years to come. The best foresight is no replacement for active surveillance and remediation for at least two hundred years to come.

In summary, this is a bad time to begin the experiment of regulation, safe closure, and extended monitoring for uranium projects in Quebec. The risk is high that foreseeable economic and environmental issues will overcome any economic benefits. This is an industry at risk, and it already has supplies for many, many years to come. Quebec does not need to gamble with its environment to support the uncertain future of nuclear power.

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I. There Is a Lasting Oversupply of Uranium

Uranium ore is the first step in a multi-year fuel cycle process that results in fuel for civilian nuclear power plants. Unrefined uranium ore poses far less risk from radioactivity than the more refined steps in the fuel cycle. The ore, however, is still quite dangerous for both humans and the environment. For that reason, uranium mining is closely supervised in the U.S. and Canada as well as many other countries.

Uranium ore is refined into triuranium octoxide (U3O8), a commodity that can be bought and sold on the global market. U3O8 is often referred to as "yellowcake." Since 2007, the prices of U3O8 and other components of the nuclear fuel cycle have fallen dramatically.

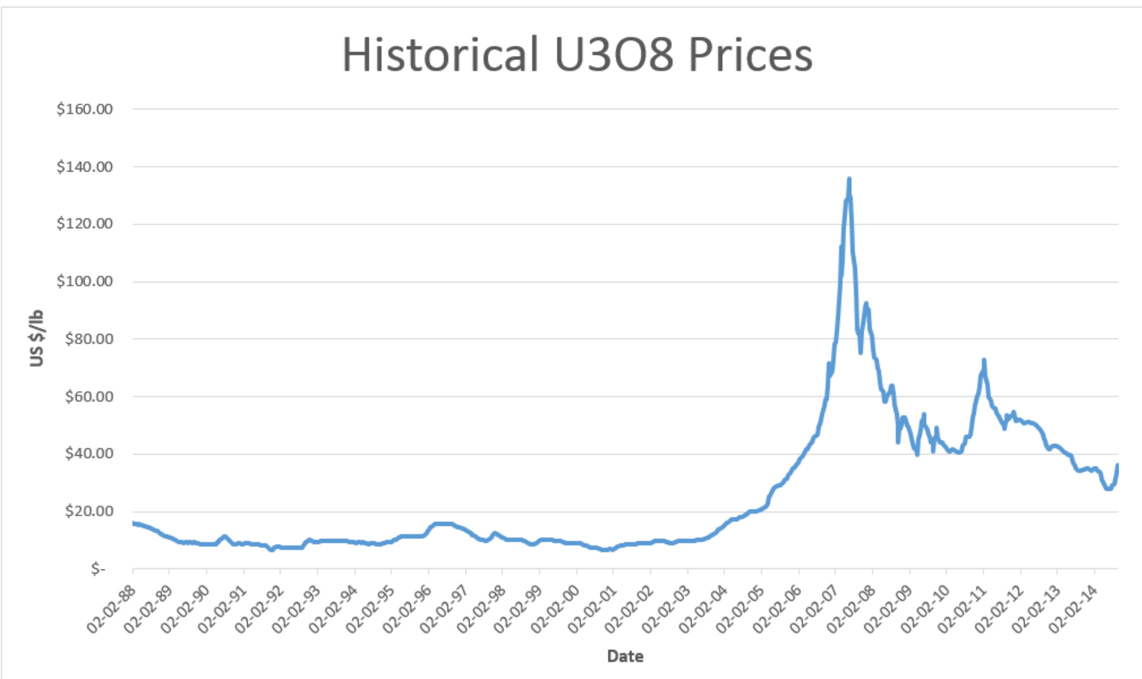

Figure 1 – Historical U3O8 Prices

The profound downturn in prices reflects a number of different factors:

1. On March 11, 2011, three units at Fukushima, Japan failed catastrophically due to the combined impact of a tsunami and an earthquake. Control of the situation is still very much in doubt with recent news stories reporting sharp

increases in release of radiation. Japan, France, and Germany have reduced their nuclear programs.

2. Three massive U3O8 mining projects – Cigar Lake (Saskatchewan, Canada), Four Mile (Australia), and Husab (Namibia) – are scheduled to enter into operation in the near future. The per-unit costs of these projects are lower than the forecasted cost of small-scale mines like those proposed in Quebec by a considerable degree, which is likely to contribute to the poor economics for small uranium projects.

3. Existing nuclear plants are aging rapidly. Although the nuclear industry is optimistic about the ability to maintain the lifetime of these older units, the evidence suggests that a substantial proportion will be closing in years to come. For instance, Gentilly-2, Hydro-Quebec's nuclear plant, closed after only twenty nine years in operation.

4. Hydraulic fracturing (also known as fracking), a revolutionary shift in oil and gas technology, has reduced natural gas prices far below previous levels. At current market prices, the nuclear industry in the U.S. is no longer competitive and U.S. demand for uranium is therefore likely to fall significantly.

These factors imply low U3O8 prices for the next decade.

Many firms forecast future commodity prices. One, the Royal Bank of Canada (RBC), provides forecasts of U3O8 on a quarterly and annual basis. The RBC forecast is widely respected and frequently used. In fact, the change in their forecast in July 2014 is commonly regarded as the cause for a major downward reevaluation of equity prices in the uranium industry.[2]

The Royal Bank of Canada (RBC) released an updated forecast of U3O8 prices on July 11, 2014.[3] The RBC forecast is fairly intuitive and quite transparent. The forecast predicts a lengthy period of continuing lower uranium prices. Their approach argues that investors will not develop additional uranium projects until the market price will cover the costs and ensure a 15% profit. Reduced to its underlying logic, their

[2] Koven, Peter. "Uranium Stocks Tumble after RBC Takes Axe to Price Forecasts," June 5, 2014 Financial Post. Retrieved on 11/03/14 from http://business.financialpost.com/2014/06/05/rbc-annihilates-uranium-price-outlook/?__lsa=65cd-c050

[3] Metal Prospects Uranium Market Outlook – Third Quarter 2014, RBC Capital Markets, 11-Jul-2014. < https://rbcnew.bluematrix.com/docs/pdf/f13c9154-b3ed-4478-92a8-adb8ea4cf66b.pdf>

forecast is simply their estimate of fully allocated cost applied on the date when new production is needed.

There a number of reasons, however, why this forecast is too optimistic.

The method behind the RBC forecast is to find the date when it is predicted that world U3O8 supply will exactly match demand. At this point, they assume that spot prices (the current market price at which the asset may be bought or sold for immediate payment and delivery) will match the fully allocated cost of U3O8 production (the total cost incurred in the production of U3O8, including all direct and indirect costs). Alfred Marshall, the British 19th century economist who codified the modern "laws" of economics, pioneered this straightforward approach.

Since RBC calculates that supply will exceed demand for years to come, there is no reason for uranium prices to meet the fully allocated cost of new production. Their short term forecast is that uranium prices will stay low until demand/supply balance is achieved in 2021.

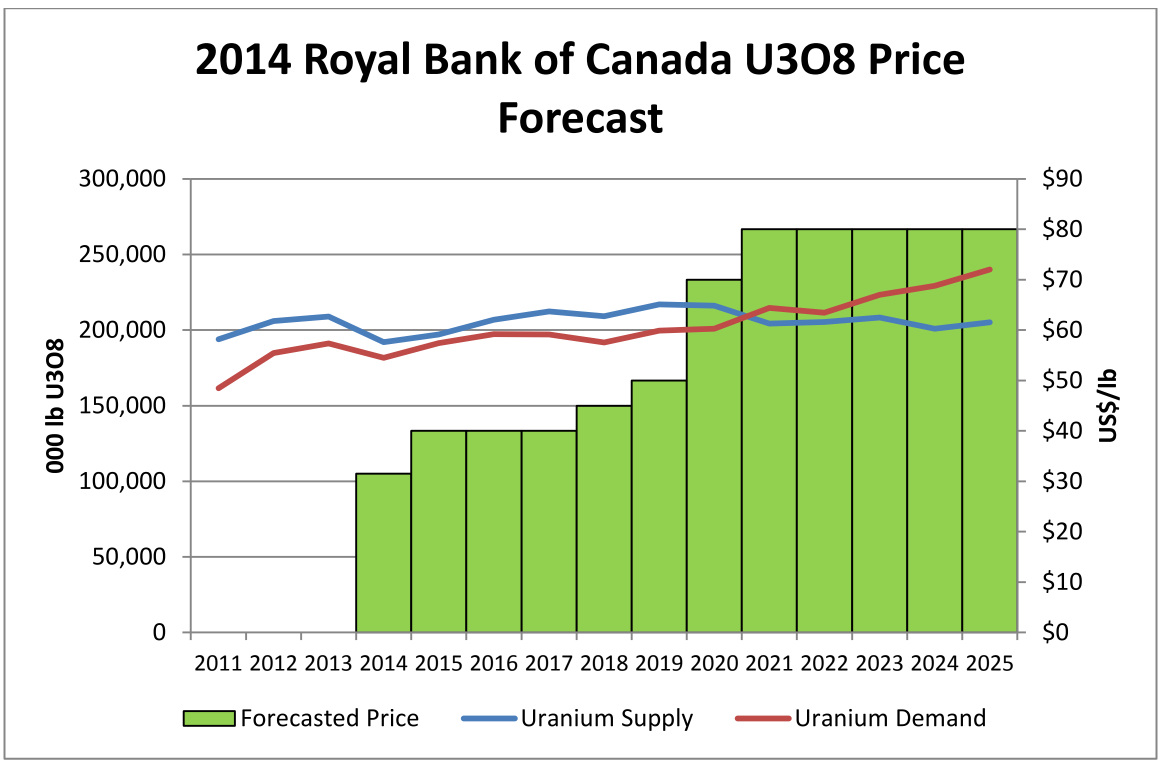

Figure 2 – 2014 RBC Price Forecast of U3O8

The devil is always in the details in forecasts such as these. Uranium, like oil, is a particularly difficult commodity to forecast since the nuclear fuel cycle is an oligopsony where a number of the suppliers are either inexact or untruthful. In the case of U3O8, the problem is complicated by the ten-year processing period from U3O8 mining to intermediate processing, and, finally, the six-year fueling cycles in commercial nuclear plants. U3O8 is the "caboose" on a very, very long train. As the locomotive slows, the impact on the last cars of the train can be quite surprising.

In the case of U3O8, the normal doubts about the value of future forecasts are much stronger than for other industries, due to the lack of information in the industry as well as the presence of a very concentrated group of market participants. Simply stated, this is an exceedingly opaque industry with an oligopsonistic market structure.

In 2007, UxC, a leading consulting firm that reports U3O8 prices, agreed to provide settlement data for a forward market (i.e. a market for future delivery) in U3O8 at the Chicago Mercantile Exchange (CMX). The viability of such markets is an interesting study in itself. When commodity prices become inexplicable, forward markets tend to disappear simply because no one is willing to bet on forecasts. This is the case of the UxC Uranium U3O8 future contract on CMX, that has zero volume traded and minimal offers.[4] The single forward market clearly indicates that there is little credibility given to market forecasts.

Traditionally, the relationship between actuals and forecasts for U3O8 is very poor:

[4] http://www.cmegroup.com/trading/metals/other/uranium_quotes_settlements_futures.html?cmeTradeDate=03%2F10%2F2014

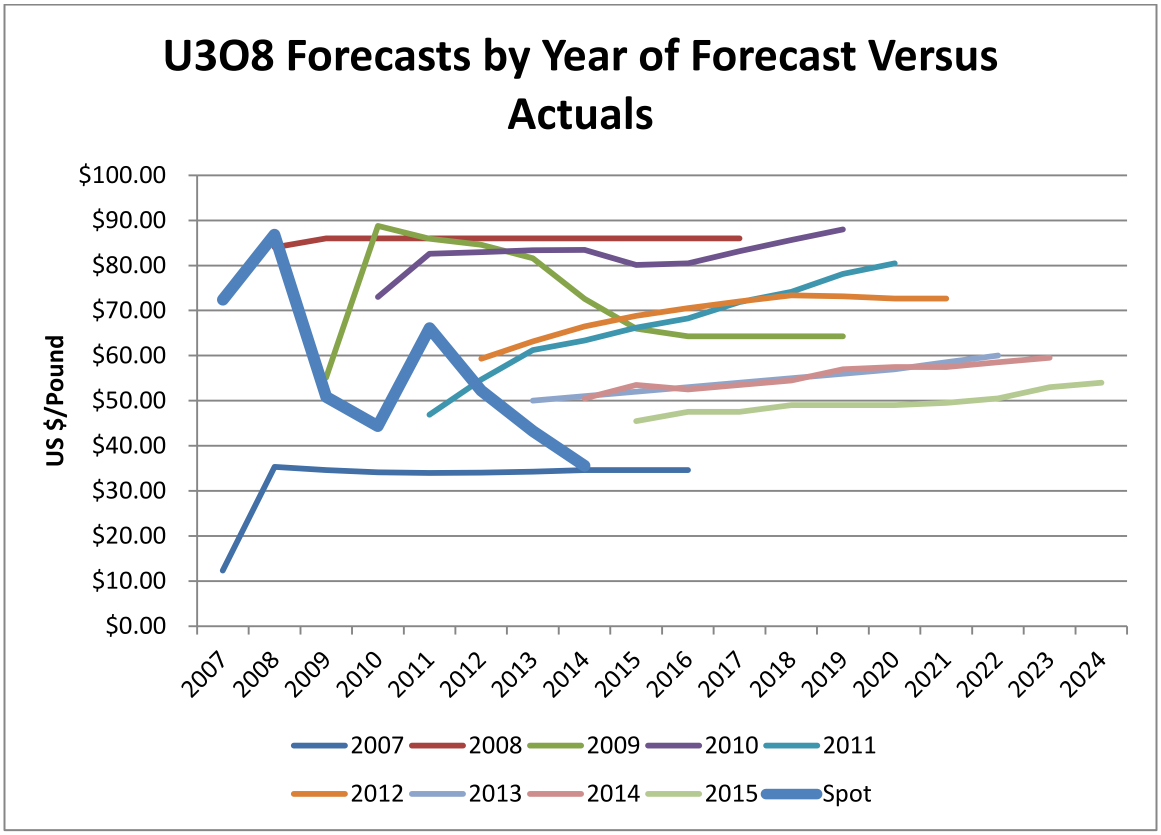

Figure 3 – U3O8 Forecasts versus Actuals

Source: Columbia generating Station Fuel Plans 2007 to the present.

Statistically, the forecasts have had no relevance to future actuals since 2007. This is not a surprising result for a concentrated oligopolistic market with very limited data. In fact, a naïve forecast that predicts that the current price will simply be the same as last year's would appear to be vastly more accurate; such an approach would explain 72.8% of the variance of prices, with a statistical significance of 99.9%. This reflects common sense: if you have no idea of what the future holds, you will simply accept last year's experience as the best guide to next year.

The primary problem in forecasting the supply and price of uranium is a lack of consistent and accurate data concerning market participants in Russia and other low-transparency areas.

Another problem with the RBC forecast in particular is the Bank's apparent assumption about the state of the world's nuclear industry. RBC's forecast keeps the size of the world nuclear industry at the current level and then expands from that level. Unfortunately, the assumption that nuclear units were unlikely to close in 2013 was gravely in error. In fact, the International Atomic Energy Agency (IAEA) reported that six plants with a cumulative capacity of 5,849 net megawatts closed in 2013 – 1.5% of total world capacity.[5] In the troubled market for nuclear power, this error in the RBC forecast will only worsen over time as more plants close.

In the current environment, three nations with large nuclear fleets are reevaluating their energy strategies – Japan, Germany, and France.[6,7,8] In the U.S., pressure has increased on commercial nuclear units as market prices for electricity fall below the cost of production for nuclear power.[9] Altogether, 114 plants are at risk of permanent closure in these four countries alone.

As a nuclear plant ages, it faces a rapidly increasing probability of closure. The average nuclear plant, both in North America and in the world as a whole, is reaching 30 years of commercial operation. The design and construction of these plants dates back to the late 1960s. The technology was state of the art in those days. However, this was also true of eight track tape players and telephone modems.

While some plants have been retired due to catastrophic failure, the majority of retirements are due to an economic recognition of the cost of retrofits to meet operating and safety standards. In the U.S., one of the few countries where data is readily available, the cost of retrofitting a plant is $50 to $80 million per reactor per year, which adds to the economic pressures for closure.

The average global commercial nuclear reactor is now twenty-eight years old. Historically, the average age of a commercial nuclear reactor when closed and decommissioned has been just over twenty three years.[10]

[5] NUCLEAR POWER REACTORS IN THE WORLD 2014 Edition, IEAE, 2014, pages 46-52.
[6] http://www.dw.de/merkel-shuts-down-seven-nuclear-reactors/a-14912184
[7] http://www.ft.com/intl/cms/s/0/f9961e7c-fe3e-11e1-8228-00144feabdc0.html#axzz3IQaLRL7b
[8] http://www.csmonitor.com/Environment/Energy-Voices/2014/1020/Au-revoir-nuclear-power-France-eyes-an-energy-shift-of-its-own
[9] Cooper, Mark. "Renaissance in Reverse." July 18, 2013. See Appendix C, v.
[10] Age of operating and decommissioned reactors from IAEA Power Reactor Information System, retrieved 11/14/2014 from http://www.iaea.org/PRIS/WorldStatistics/OperationalByAge.aspx

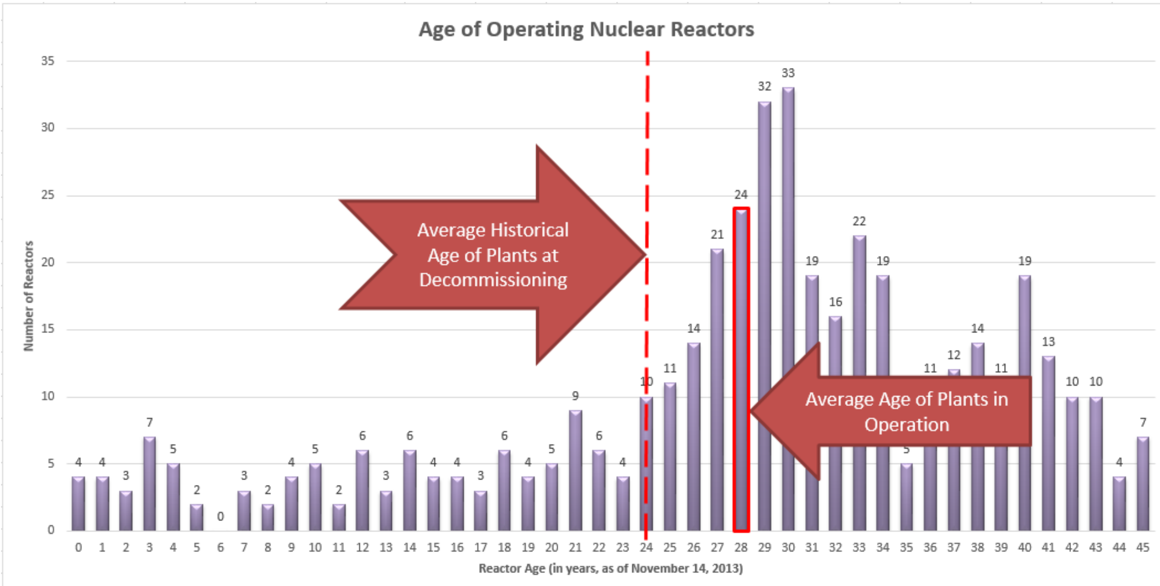

Figure 4 – Existing Global Nuclear Plants

Overall, RBC's forecasts reflect an overoptimistic assumption that the retirement of nuclear plants is at an end. The assumption is never stated, but it is a central determinant of the future demand and supply balance that underpins the RBC's forecast. This is all the more puzzling since the IAEA data indicates that 26 nuclear plants have been retired over the past five years.

Data from the IAEA allows for a simple demographic analysis of the life expectancy of the world's nuclear fleet. As with life tables for demographic forecasting, it is easy to calculate the probability of closure for each age cohort. Not surprisingly, the risk of closure climbs rapidly with plant age.

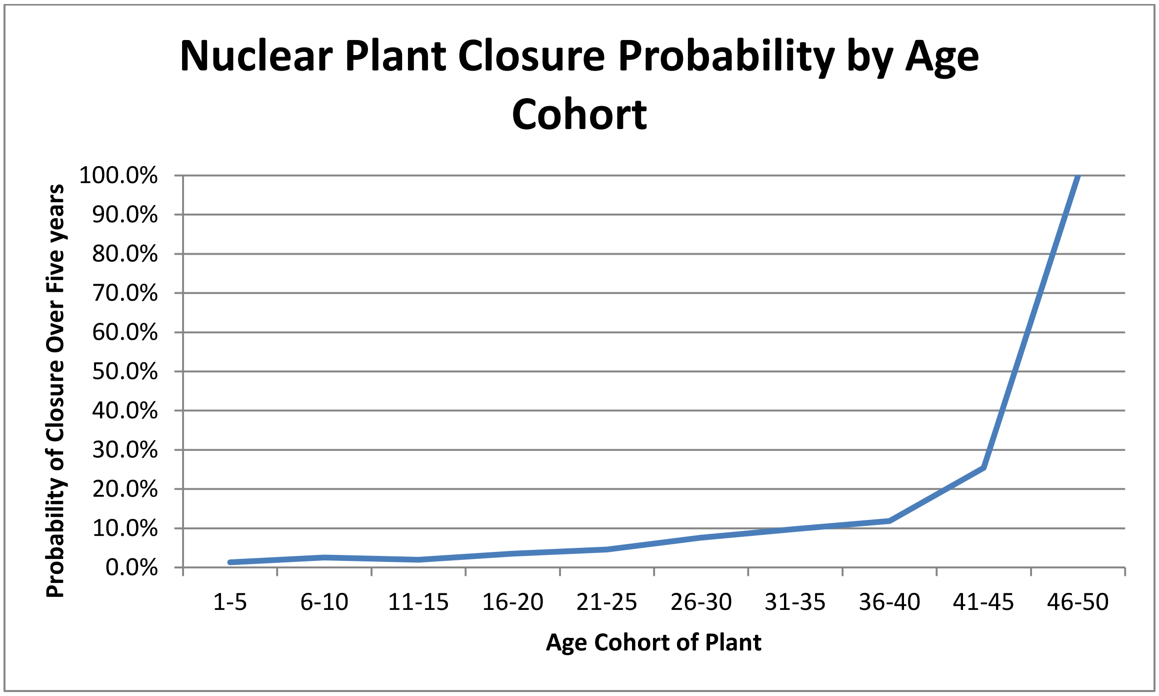

Figure 5 – Nuclear Plant Closure Probability by Age

It should be noted that the IAEA statistics indicate that the probability of closure reaches 100% during the period between 46 through 50 years of age. This reflects the fact that no nuclear reactor that is currently operating has reached an age older than 48.

Age (years)	Probability of retirement between ages x and x + n	Number surviving to age x	Number of retirements between ages x and x + n	Plant-years lived between ages x and x + n	Total number of plant-years lived above age x	Expectation of future years of plant operation at age x
x	n qx	lx	n dx	n Lx	Tx	ex
0	1.4%	440.0	6.0	437.0	13,592.5	30.9
1-5	2.6%	424.0	11.0	855.5	11,407.5	26.9
6-10	2.0%	407.0	8.0	1258.5	9,315.0	22.9
11-15	3.6%	392.0	14.0	1643.5	7,300.0	18.6
16-20	4.6%	373.0	17.0	2008.0	5,375.0	14.4
21-25	7.6%	342.0	26.0	2337.0	3,552.5	10.4
26-30	9.9%	213.0	21.0	2539.5	1,907.5	9.0
31-35	11.9%	126.0	15.0	2658.0	895.0	7.1
36-40	25.4%	59.0	15.0	2709.5	302.5	5.1
41-45	100.0%	14.0	14.0	2716.5	45.0	3.2
46-50	100.0%	4.0	4.0	2718.5	10.0	2.5

Table 1 – Expectations of Plant Longevity

It is relatively easy to apply the closure probabilities to the existing nuclear plants. Between 2014 and 2019 we can expect the closure of 40 nuclear stations. Between 2015 and 2024 we can expect the closure of an additional 73 nuclear stations. Translated into generating capacity, this means that the RBC forecast has overstated 31,463 MW over the first five years and an additional 57,238 MW in the second five year period.

While failing to consider plant closures, it is apparent that RBC's estimates do include nuclear plants that are planned to come online in the next decade. The inclusion of these future projects is dubious. Of the 67 plants under construction (as of July 2014), at least 49 have encountered construction delays, and eight have been categorized as "under construction" for more than 20 years.[11] In China, the country building the most new reactors, delays are becoming undeniable. The China Nuclear Energy Association (CNEA) estimated in 2010 that by 2020 installed capacity and reactor units under construction would total 130 GW. In 2011, that estimate had fallen to 100 GW, and in 2014, the head of CNEA announced an estimate of 88 GW.[12] However, even if all 67 projects currently under construction come online by 2020, when one factors in all likely closures, installed worldwide nuclear capacity will at best stagnate, and at worst slightly drop.

Subtracting expected nuclear plant retirements from the RBC's demand forecast gives a much slower ramp-up to the date when demand for uranium equals supply. Whereas RBC's forecast predicts that the price of U3O8 will increase to $80/lb in 2021, our forecast recognizes that a majority of existing nuclear stations are facing the end of their lifetimes. This reduces the demand for uranium and extends the period of oversupply beyond the forecast horizon.

[11] The World Nuclear Industry Status Report 2014. Schneider, Mycycle and Froggatt, Antony. Paris, London, Washington DC, July 2014.
[12] Xinhua, "China's nuclear power installed capacity to reach 88 GW by 2020", 20 April 2014, see http://english.people.com.cn/business/8603754.html, accessed October 31, 2014.

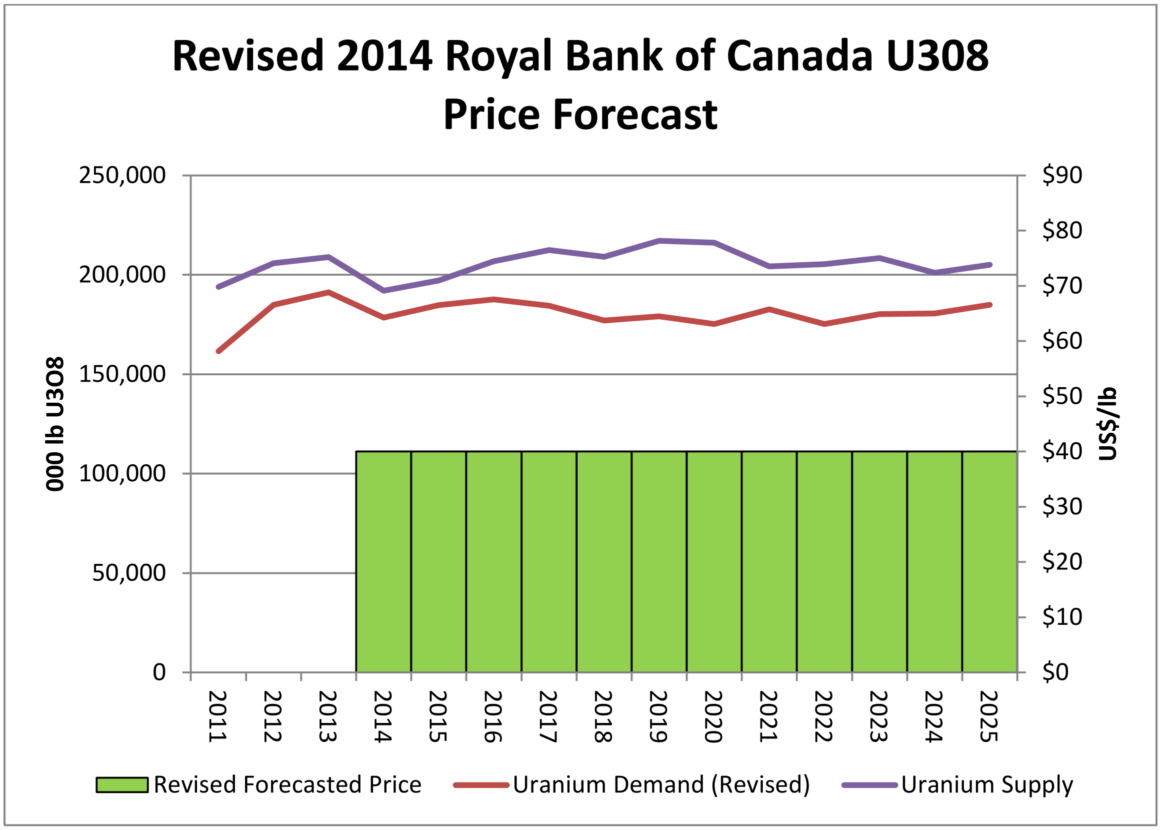

Figure 6 – Revised 2014 RBC Price Forecast of U3O8

As with any forecast, the excess of uranium supply over demand over the next decade reflects assumptions we have made regarding new supplies.

In our re-assessment of RBC's supply forecast, we have eliminated projected new mines until required, with three exceptions. Three major projects, Cigar Lake (in Saskatchewan), Four Mile (Australia), and Husab (Namibia), are expected to be ready to enter into production in the near future. We have assumed that Cigar Lake and Four Mile will be in operation this year. Husab is a somewhat different matter. Husab has a forecasted cost of US $32/lb which places it about on par with recent spot prices.[13] Husab's forecasted output is so large that it is effectively self-defeating – starting Husab in the current environment will drop uranium prices to levels as low as or even lower than the site's operating costs.

[13] Definitive Feasibility Study demonstrates viability of the Husab Uranium Project, Extract Resources, 5-Apr-2011, page 2. Retrieved 11/24/2014 from http://swakopuranium.com/downloads/media/announcements/2011/2.10.47%20110405%20EXT%20DFS%20completion.pdf

However, it should be noted that Husab is owned by Swakop Uranium, 90% of which is owned by a subsidiary of the China General Nuclear Power Company (CGN).[14] Regardless of economic conditions, CGN may be politically motivated to move ahead with development of Husab; Chinese leaders are striving toward self-reliance in nuclear power generation, and the political goal of having a Chinese-owned and operated source of nuclear fuel may outweigh economic common sense. If the Husab project proceeds, then there will be even more downward pressure on the price of U3O8—pressure that will last for decades, as Swakop reports that the expected life of the mine is more than 20 years.[15] Here we have assumed that Husab will proceed on schedule, and the price of uranium will be below long-term marginal cost for the entire forecasted period.

The result of our re-assessment of the RBC forecast predicts a surplus of U3O8 over requirements for the next decade. The primary difference between our forecast and the RBC forecast is the inclusion of nuclear plant retirements, which makes our forecast more realistic.

All indications are that the market for U3O8 will be in decline for the immediate future – at least until 2025. During this period we can expect mining projects – especially smaller, less economic mining projects – to be delayed or cancelled. This has certainly been the experience in 2014.

[14] Swakop Uranium website, retrieved on 11/14/2014 from http://swakopuranium.com/ob-qa.php
[15] http://swakopuranium.com/ob-qa.php#c

II. Small Uranium Mines Are Not Competitive

Uranium mining projects begin with exploratory prospecting to determine the amount and quality of uranium present.

In Canada, following exploration, the licensing process begins under the *Nuclear Safety and Control Act*. The Canadian Nuclear Safety Commission must be convinced that the applicant is qualified and will adequately plan to protect the environment, health, and safety in accordance with all national and international laws.

Normal projects go through four stages of licensing over their operating lifetime, and decommissioning cost estimates are updated at each stage of licensing. Aboriginal and other stakeholder groups are consulted as part of the licensing process.[16]

In Quebec, the deposits explored so far have far lower grades of uranium than those currently operating in Saskatchewan. For example, uranium projects in Saskatchewan have proven reserves at grades between 0.5% and 18.3% U3O8. In Quebec, the deposits explored so far have far lower grades of uranium. For example, Uracan Resources has found an Indicated Resource estimate of 21.5 million tons at an average grade of 0.014% U3O8 at their North Shore project.[17] Likewise, Virginia Energy found ore grades from 0.1% to 1.31% U3O8, similar to the nearby Matoush deposit in the Otish Basin.[18] All available information suggests that uranium deposits in Quebec are likely to be small-scale, low-grade mines.

In light of the re-assessed forecast discussed above, the logical conclusion is that small-scale uranium projects will not be viable over the next ten years, because they almost certainly operate on economics inferior to massive ones like Husab in Namibia.

This theory has been borne out by the shelving of several smaller-scale projects in 2014. Two good examples are the Millennium project in Saskatchewan and the Matoush site in Quebec. The complexities of financing the latter have provided significantly more materials – studies, pro formas, and reports – than the average project. The financial details of the Matoush project are summarized in Appendix B.

16 http://www.cnsc.gc.ca/pubs_catalogue/uploads/Licensing_Process_for_New_Uranium_Mines_and_Mills_in_Canada_INFO_0759_Revision_1_e.pdf

17 http://www.uracan.ca/s/Quebec.asp?ReportID=363595

18 http://www.virginiaenergyresources.com/s/OtishBasin.asp

The Millennium project is a site in Northern Saskatchewan, approximately 30 km north of the Key Lake uranium mill. Uranium deposits were originally discovered there in 2000. The proposed mining operation at the site was to be a joint venture between Cameco, Areva, and Japan-Canada Uranium Co. Ltd (JCU), but in 2012 Cameco purchased Areva's share, increasing its own interest in the project to 69.9%.[19]

The Millennium uranium deposit has 75.9 million pounds of indicated U3O8 resources at a grade of 2.39%.[20] The project would have been substantial although smaller than the Cigar Lake and McArthur River deposits, two other Cameco mines in Saskatchewan.[21] In 2013, Cameco submitted the final Environmental Impact Statement to Canadian regulators, which received approval from the Saskatchewan Ministry of the Environment. However, the company reports on its website that "[i]n May 2014, Cameco wrote to the CNSC to withdraw our application, citing economic conditions that were not favourable to proceeding further with the Millennium approval."[22] The development of the project was not far enough along for Cameco to have released detailed estimates of per-pound costs for the site, though clearly those costs were too high to proceed, despite Millennium's proximity to an already-operational mill at Key Lake.

The proposed Matoush project site in Quebec was also shut down this spring. Falling U3O8 prices would not have supported this relatively small project. The problem, in a nutshell, is scale. The Namibian project, Husab, is a massive undertaking with significant economies of scale. The cost per pound of uranium is low at Husab, which is estimated to produce 10 million pounds of U3O8 a year at a cost of US $32/lb.[23]

In contrast the Matoush project had a <u>total</u> forecasted output of 17.8 million lbs of U3O8 at a cost of US $51/lb (see Appendix B for a more detailed review of the economics of the Matoush project). Matoush was supposed to begin commercial operations in 2013. Quebec authorities have not granted the Matoush project the required permits to go ahead. The site's owner, Strateco Resources, announced the closure of

[19] Cameco Corp., 2014. Retrieved on 11/04/14 from: http://www.cameco.com/northernsk/cameco_in_north/operation_major_projects/millennium/
[20] 2013 Cameco Annual Report.
[21] Cameco Corp, 2010. Millennium Mine Project: Fact Sheet. Retrieved on 11/04/14 from: http://www.cameco.com/northernsk/pdf/Millennium_Project_Fact_Sheet_2010.pdf
[22] Cameco Corp., 2014. Retrieved on 11/04/14 from: http://www.cameco.com/northernsk/cameco_in_north/operation_major_projects/millennium/
[23] Metal Prospects Uranium Market Outlook – Third Quarter 2013. RBC, 18-Jun-2013. Page 11.

the project on June 12, 2014.[24] The timing of this announcement is significant. In the previous week, the highly respected analysts at the Royal Bank of Canada announced a 40% reduction in their U3O8 price forecast. This resulted in a major fall in the stock prices of all U3O8 producers.[25] The economics underlying a site the size of Millennium were clearly questionable enough to put the project on hold, which makes the viability of an even smaller mine like Matoush even more suspect.

The U3O8 industry is increasingly dominated by "mega-mines", like Husab, Cigar Lake, and Four Mile. Economies of scale, locational advantages, and ore grade favor a few large, well-financed projects for the immediate future. In this climate, small-scale projects are unlikely to be profitable.

III. Decommissioning of Uranium Mining Sites Poses Long Term Challenges

Best practices in the industry for new uranium projects are reflected in the detailed rules in Saskatchewan and at the U.S. Nuclear Regulatory Commission. The rules are largely parallel, but differ in many details. The most important distinction being Canada's lack of transparent planning for decommissioning as well as advanced funding.

The difference in transparency between the U.S. and Canada is substantial. In the U.S. the decommissioning estimates are subject to review at the Nuclear Regulatory Commission and can be reviewed – and debated – by all interested parties.[26] In Canada, decommissioning estimates are subject to review by government officials, but are much less transparent to the public.

Moreover, financial assurances are not always in line with eventual decommissioning costs. The history of uranium production shows that unforeseen contingencies can sometimes demand funding far in excess of existing financial assurances. Production capacity at current uranium mines and mills in Canada is generally higher than in the US, while financial assurances for decommissioning and reclamation are lower in Canada:

[24] Strateco Shuts Down Its Matoush Camp To Minimize Operating Costs. Guy Hebert, 12-Jun-2014.
[25] Uranium stocks tumble after RBC takes axe to price forecasts, Peter Koven, Financial Post, 5-Jun-2014.
[26] For NRC-regulated sites, financial assurance information can be found online at http://adams.nrc.gov/wba/

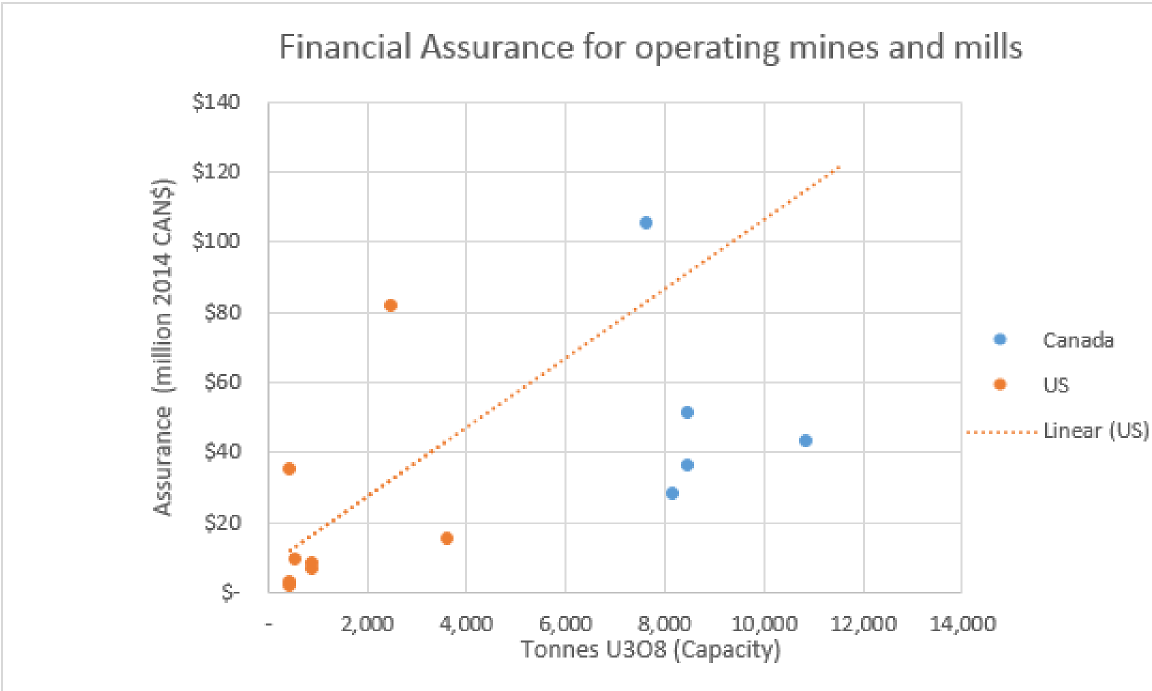

Figure 7 – Financial Assurances for Operating Mines and Mills

Financial assurances vary based on site-specific factors including hydrology and geology. Although the small number of projects makes a statistical argument difficult, the chart above indicates that U.S. financial assurances appear significantly higher than those in Canada, in proportion to the tonnage of U3O8 produced.

In addition, long term monitoring expenses are not clearly identified in Canada. By contrast, in the US, Title II uranium sites have an additional surety requirement of at least US$910,000 for long term monitoring by the Department of Energy.[27]

A 1995 study commissioned by the German Federal Ministry of Economics provides interesting insights into the international differences in remediation costs.[28]

[28] Kosten der Stillegung und Sanierung von Urangewinnungsprojekten im internationalen Vergleich - Einflußgrößen und Abhängigkeiten - Auszug aus dem Abschlußbericht zum Forschungsauftrag Nr.37/93, im Auftrag des Bundesministeriums für Wirtschaft durchgeführt von Uranerzbergbau GmbH, BMWi Studienreihe Nr.90, Bundesministerium für Wirtschaft external link, Bonn 1995 [Comparison of Decommissioning and Remediation Costs of Uranium Producing Projects on an International Basis; with summaries in English, French, Spanish, and Russian]

Land	Produktion	Tailings	Gesamtkosten	Spezifische Kosten	
	t U (incl. 1992)	Mio t	Mio US$ (1993)	US$/ t Tailings	US$/lb U_3O_8
Australien	54.225 6) (49.625)	98,7 (18,7)	85,10 (63,30)	0,86	0,60 (0,49)
Bulgarien	4) 21.871	23,0	173,10	7,53	3,04
(Deutschland O. und W.) nur Deutschland West (nur Deutschland Ost)	(218.463) 650 (217.813)	0,2 (160,0)	15,15 (7.878,79)	75,76 (49,24)	8,97 (13,91)
Frankreich	70.038	31,4	128,45	4,09	0,71
Gabun	21.446	6,5	30,13	4,64	0,54
Kanada	257.702	160,6	77,10	0,48	0,12
Namibia	53.074	350,0	53,20	0,15	0,39
Niger	56.845	17,2	79,87	4,64	0,54
Schweden	200	1,5	20,98	13,99	40,35
Spanien	1.145	1,2	14,82	12,35	4,98
Südafrika	143.305	700,0	81,97	0,12	0,22
Tschech. Republik	4) 101.901	48,8	433,33	8,88	1,64
Ungarn	19.970	19,0	78,40	4,13	1,51
USA, gesamt davon in UMTRA Title I davon in UMTRA Title II	5) 310.000 56.000 254.000	222,9 31,3 191,6	2.428,96 2.140,00 288,96	10,90 68,37 1,51	3,01 14,70 0,44
Gesamt	1.141.276	1) 901,0 2) 780,0 1.681,0	1) 3.596,79 2) 103,74 3.700,53	1) 3,99 2) 0,13 2,20	3) 1,25

Figure 8 – Decommissioning Costs of Uranium Projects

According to the German Ministry of Economics study, Canada created 160.9 million tons of tailings and paid $0.48 per ton in remediation costs in the years leading up to 1992. The U.S. produced 222.9 million tons of tailings and paid $10.90 per ton for decommissioning. Uranium mine decommissioning in the U.S. is historically so expensive due to the existence of UMTRA Title I legacy sites which started production before federal law regulated site development and reclamation. Excluding UMTRA Title I legacy sites, the per-ton cost of decommissioning for U.S. uranium projects was $1.51.

Interpretation of the results of the German Ministry of Economics study should recognize some important caveats. As the study states:

> The predominant project-specific or location-specific factor influencing the specific rehabilitation costs is determined by deposit parameters, such as ore grade, mineralogy of ore and wall rock, hydrogeological conditions, deposit size as well as morphology and depth of the orebody. The relatively small specific rehabilitation costs for rich ore deposits in the Northern Territory, Australia, and in North Saskatchewan, Canada, may serve as an example: Due to the high ore grade of these deposits, processing results of comparatively small residue quantities per unit of production (lb of U3O8). Accordingly, the storage of the tailings involves relatively low costs. In contrast to this, uranium production from low grade sandstone deposits in the western part of the US involves large quantities of tailings and hence, considerably higher disposal costs.
>
> In Ontario/Canada low ore grades result in large quantities of residues. However, their disposal does not involve high specific costs because of the large deposit size and the climactic, ecologic and demographic conditions which permit a low-cost, so-called "wet storage". Among other things, this method prevents the oxidation of the pyritic tailings and, therefore, acid generation. In certain cases, wet storage may not be possible because of the unfavorable hydrologic position of the tailings requiring either the relocation of the tailings or the stabilization or the reconstruction of the outer dams.
>
> Any of these options would result in considerable additional expenditure.[29]

The only mines currently operating in Canada are four sites in Saskatchewan with extremely high ore grades. Provable reserves range from 0.5% to 18.3% U3O8. These are open pit or underground mining operations, which disturb land and generate large quantities of tailings as well as requiring monitoring and restricted site-use after decommissioning.[30]

A more recent study by the OECD, dating from 2002, provides similar results.[31]

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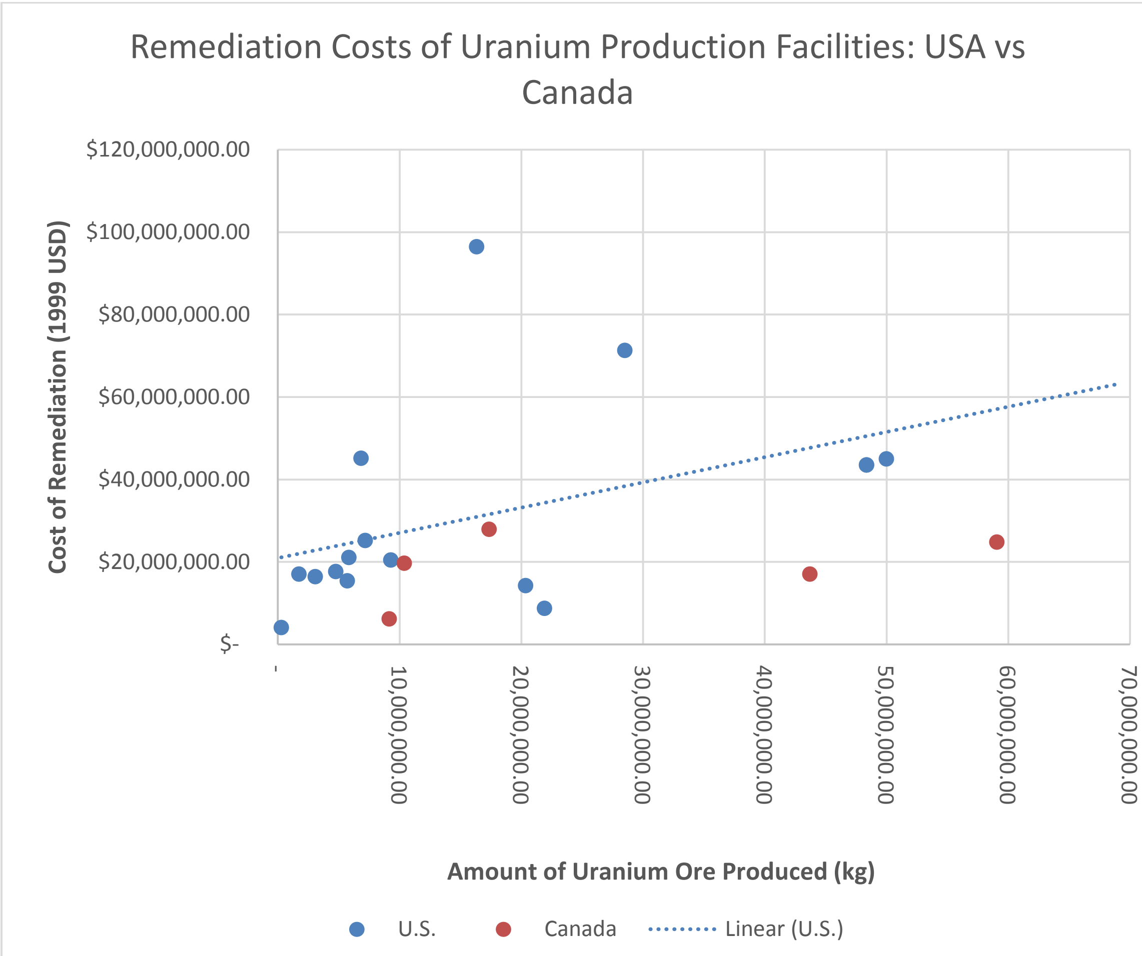
[29] Ibid., Pages 5 and 6.
[30] OECD. Nuclear Energy Agency. *Managing Environmental and Health Impacts of Uranium Mining.* 2014. Web. http://www.oecd-nea.org/ndd/pubs/2014/7062-mehium.pdf
[31] OECD. 2002 Environmental Remediation of Uranium Production Facilities.



Currently, uranium extraction sites in the US have higher financial assurances for decommissioning than those in Canada per ton of U3O8 production. As noted above, national differences reflect a variety of differences in technology, climate, mineralogy, deposit size, grade, and hydrology.

In the U.S., ore grades are lower than at Canadian sites, ranging from 0.04% to 0.11%. The only uranium mining currently happening in the U.S. is In Situ Leaching, which is much less disruptive to surrounding land and allows mine sites to eventually be turned over for unrestricted use after intensive groundwater restoration.[32]

[32] Energy Information Agency. 1993. *Decommissioning of U.S. Uranium Production Facilities.* Web. http://www.eia.gov/nuclear/decommission/

Financial assurances for uranium sites are only estimates that do not always cover full decommissioning costs. The U.S. history of uranium mining demonstrates this uncertainty well. Companies can become insolvent due to fluctuations in the market, as with the Atlas Mill in Utah, which went bankrupt in 1998. Atlas Corporation left behind $6.5 million for a project that will ultimately cost taxpayers an estimated $1 billion to reclaim. Their decommissioning plan had failed to account for the site's proximity to the Colorado River, and the entire tailings pile needed to be relocated.[33,34]

Another US example of inadequate financial assurance is the American Nuclear Corporation (ANC) Gas Hills site in Wyoming. In 1996 ANC announced that they were ceasing all operations at their site, including the required reclamation and monitoring, because of a lack of working capital. The company had $5,000 to wrap up business at the site.[35,36]

Responsibility for the site was turned over to the Wyoming Department of Environmental Quality (WDEQ), which admittedly lacked experience and funding in decommissioning radioactive sites.[37] Decommissioning was put on hold for several years, and in 2002 it was estimated that ANC's $3.2 million reclamation bond might only cover half of the required reclamation at the site.[38] The WDEQ's most likely course of action is to ask congress for funding. Both the Atlas Corp. and American Nuclear Corporation financial assurances were approved by regulators.

A reasonable conclusion is that existing Canadian remediation estimates are lower than those in a number of other countries – including the United States. Moreover, there is continuing evidence that even in the U.S. remediation costs may have been underestimated in many cases.

[33] United States Nuclear Regulatory Commission. *NRC AND UTAH CHOOSE DAMES & MOORE AS TRUSTEE FOR ATLAS URANIUM MILL TAILINGS PILE*. 27 Sept. 1999.

[34] WISE Uranium Project. *Decommissioning of Moab, Utah, Uranium Mill Tailings*. Web. http://www.wise-uranium.org/udmoa.html

[35] Press Release. *NRC ORDERS AMERICAN NUCLEAR CORPORATION TO STAY AT WYOMING URANIUM MILL SITE UNTIL LICENSE IS TERMINATED.* 17, May 1994. http://pbadupws.nrc.gov/docs/ML0037/ML003706173.pdf

[36] Salisbury, William C. Letter to NRC Director. 25 May, 1994. Web. http://pbadupws.nrc.gov/docs/ML0715/ML071580056.pdf

[37] Moxley, Mark. Letter to Arthur Howell. 27 Aug. 2008. Web. http://pbadupws.nrc.gov/docs/ML0824/ML082470215.pdf

[38] American Nuclear Corporation. Form 10-Q. 14 Nov. 2002. Web. http://www.sec.gov/Archives/edgar/containers/fix010/5550/0000899246-02-000020.txt

Finally, the effects of climate change must be considered when estimating remediation costs for a given project. The Ouranos publication, "Learning to Adapt to Climate Change" predicts a very different climate for northern Quebec in years to come.[39] The historical temperatures in James Bay and the area that empties into it are projected to change dramatically:

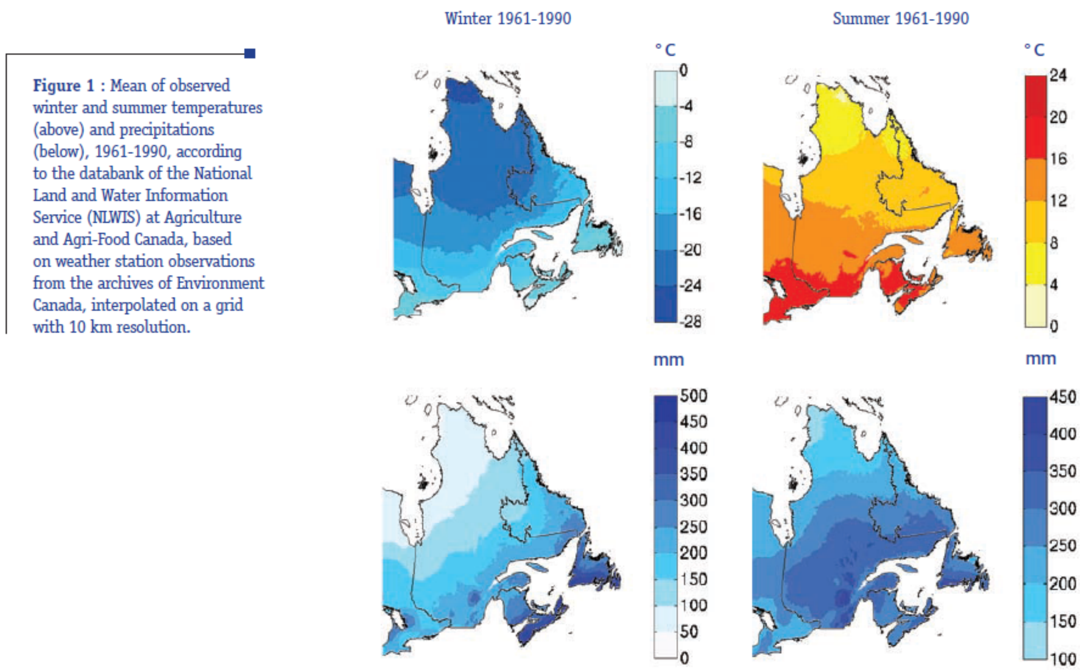


Figure 9 – Ouranos Historical Temperature Means

[39] Learning to Adapt to Climate Change, Ouranos, 2010, pages 6-8.

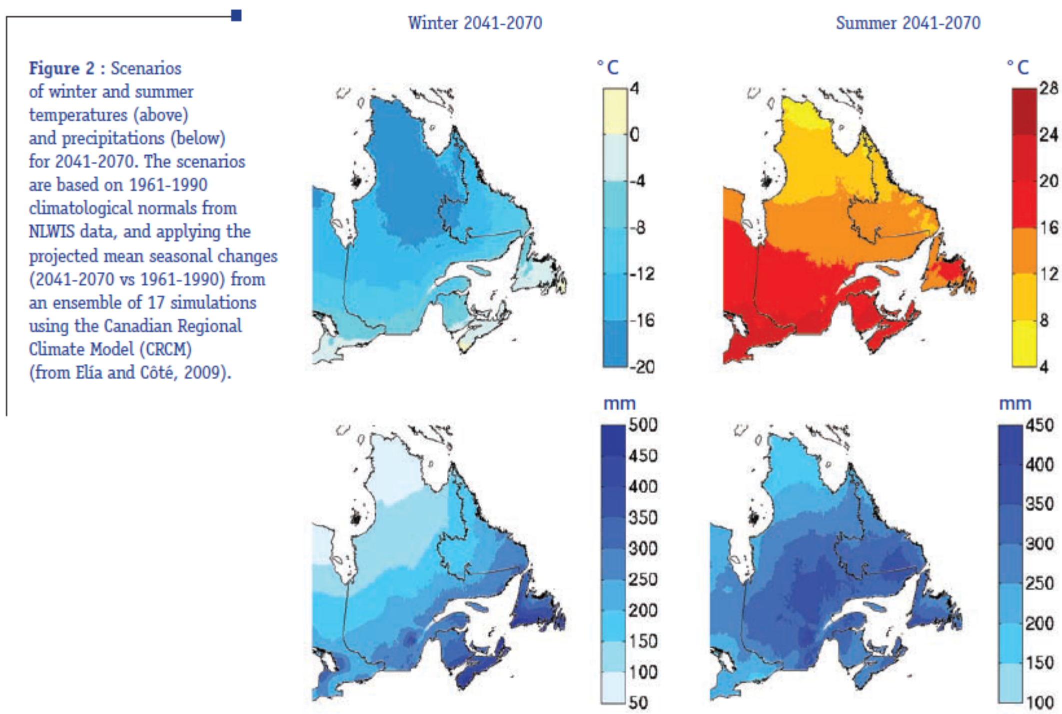
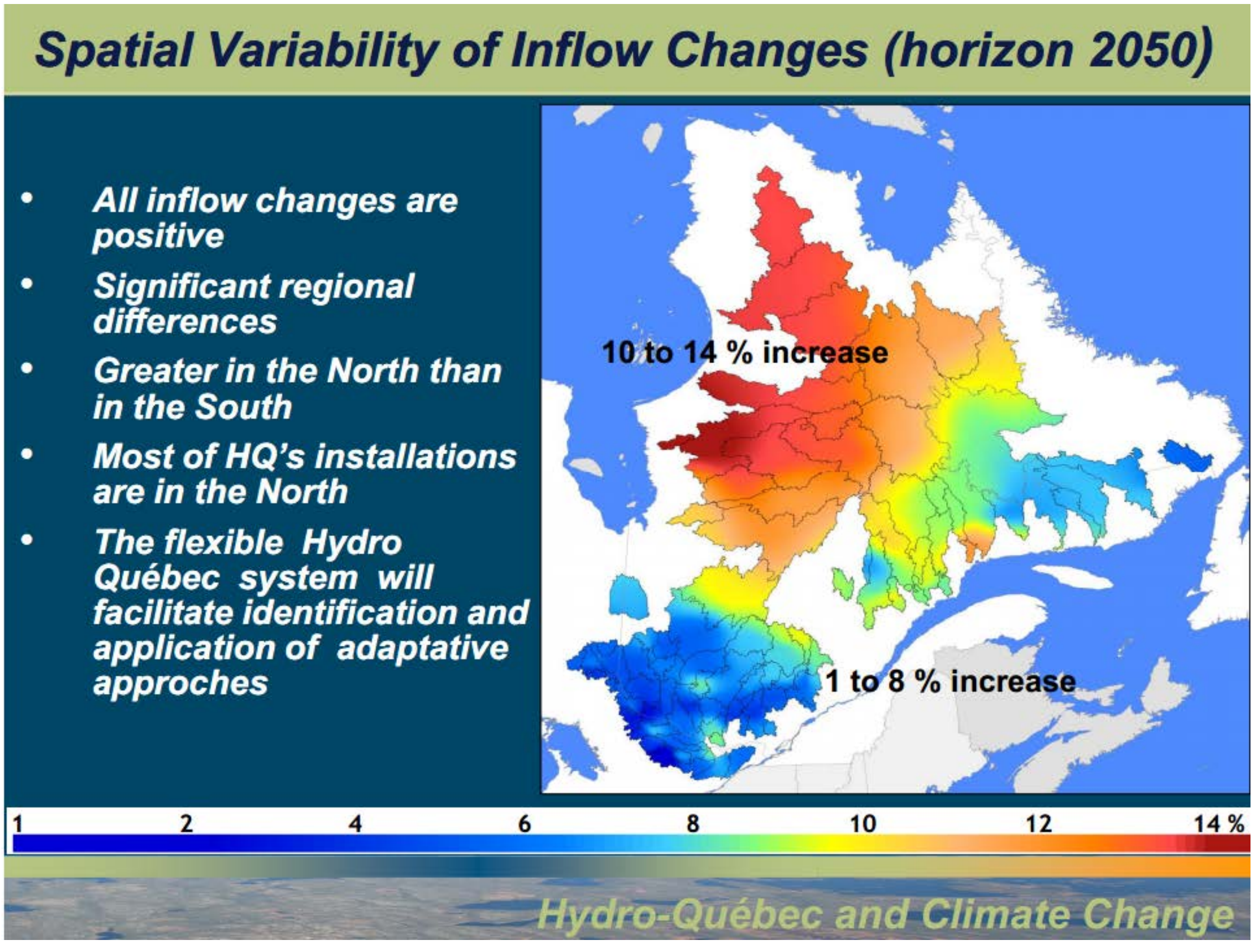


Figure 10 - Ouranos Projected Temperature Means

The change in expected temperatures for the James Bay region is very likely to change the assumptions behind any remediation and surveillance program and is also likely to be accompanied by changes in hydrology.

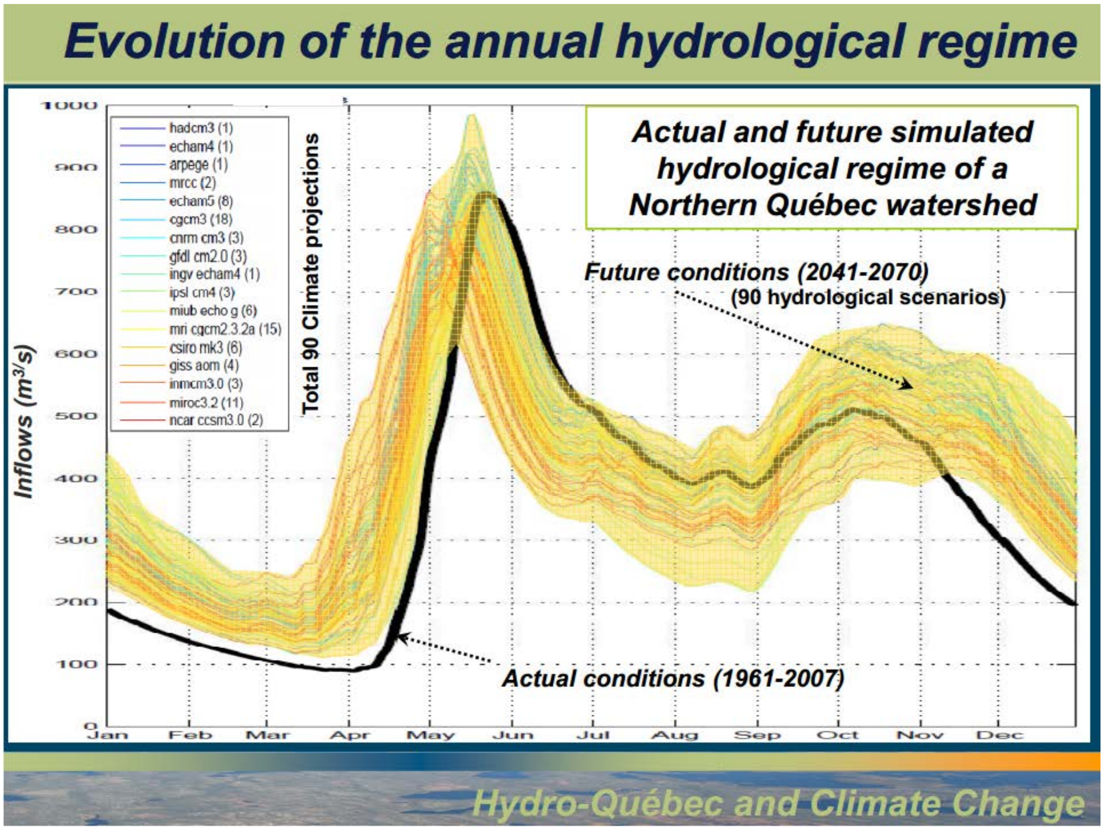
Hydro-Quebec's studies on these impacts have been summarized in many presentations. For example, in a presentation entitled "Hydro-Québec's Experience in Adapting to Climate Change", authors Ralph Silver and René Roy reported on major expected inflow changes north of the Laurentian Mountains.[40]

[40] Hydro-Québec's Experience in Adapting to Climate Change, Ralph Silver and Rene Roy, Hydro-Quebec, 15-Nov-2010.



Normally, in planning for development projects, changes occurring twenty to forty years in the future can be disregarded. In the remediation of tailings this is not the case. Hydrology impacts both water tables and erosion. Evidence from other tailings remediation sites – including the case study of Riverton (addressed in the next section) – indicates that such changes in the environment may require dramatic changes in strategy at later dates.

The level of inflows is not the only variable that is likely to change. Higher temperatures – especially earlier in the operating year – mean that the timing of flows are likely to change:



This chart indicates a shift in flows towards the spring and a significant increase of the peak when erosion of natural and manmade structures is most likely to occur.

Climate change – especially that which will affect the hydrology of the James Bay region – will almost certainly make today's assumptions concerning remediation increasingly irrelevant. In sum, planning tailing remediation solutions on the basis of historical data is likely to be as fallible as a child's sand castle when the tide turns.

IV. Today's Solutions Haven't Proved Equal to Tomorrow's Challenges

The U.S. Nuclear Regulatory Commission recommends a surveillance horizon of two hundred years for uranium mines and other facilities. While this sounds like a long time, a more appropriate horizon may be far longer. The CNSC's regulatory guide for long-term safety of radioactive waste does not cite a timeframe, and instead recommends that each licensee evaluate the potential long-term effects of their site for "the period of time during which the maximum impact is expected to occur."[41]

The famous philosopher George Santayana once remarked that "those who cannot remember the past are condemned to repeat it." The history of uranium mine remediation and surveillance has proved his point many times over. The case of Riverton is a prime example.

Riverton: A Case Study

In 1958, Fremont Metals operated a small uranium milling facility at Riverton, Wyoming which closed after five years. Today in 2014, fifty-six years later, active remediation measures are still underway. After closure, Fremont Metals covered the tailings and left the site. In 1975, a radiological survey of the land surrounding the 80 acre tailings pile found that a total of about 460 additional acres were contaminated above background levels.

The Riverton case study demonstrates that changing conditions – and environmental standards – make remediation and surveillance of uranium production sites a long term process. The eventual disposition of the site and the remediation measures are still in play after over fifty years.

The challenges that arose in Riverton, Wyoming are not unique to this one site, nor are they unique to America. They arose despite being in what is arguably the most strictly regulated and transparent jurisdiction in the world of uranium mining.

In addition, one cannot write off this example as merely an artifact of a less-enlightened time in history. Modern methods of remediation have been applied, and

[41] CNSC. *Assessing the Long Term Safety of Radioactive Waste Management.* Regulatory Guide G–320. Dec. 2006. Web. http://www.nuclearsafety.gc.ca/pubs_catalogue/uploads/g-320_final_e.pdf

continue to be applied to the area, and yet the threats of contamination and radiation persist.

Rather than being distinctive of a particular place or time, the challenges, risks, and costs discussed here will almost certainly arise in any endeavor to mine uranium.

We selected the Riverton tailings remediation program as an example for the following reasons:

1. The site is remote from population centers;
2. The major issues revolve around hydrology;
3. The site is on aboriginal lands;
4. Jurisdictional disputes are common between town, county, state, federal, and tribal authorities; and
5. Various remediation efforts have been ineffective, and some have been counterproductive.

Riverton, Wyoming is a small town organized in 1906 on land purchased from the Eastern Shoshone and Northern Arapaho Tribes and ratified by the U.S. gress.[42,43] The town was a railhead, but remained relatively undeveloped until the uranium boom times in the 1950s. The original processing mill owned by Fremont Metals was built in 1958 and operated for five years.

Various official documents describe the location:

> The Riverton, Wyoming, site is in a rural setting 2.0 mi (3.0 km) southwest of the city of Riverton in Fremont County. The per capita income in the county is $9,806 and the population in the site vicinity is predominantly Native American (DOC, 1990). The site is on private land within the boundary of the Wind River Indian Reservation (Northern Arapaho and Shoshone Indian Tribes). Contaminated material totaling 1,793,000 yd3 (1,371,000 m3) was on 140 ac (57 ha) of land at the processing site and at off-site vicinity properties. All the contaminated material was transported 45 mi (72 km) to the Gas Hills uranium district, consolidated into an active uranium tailings pile, and

[42] Legal Analysis of the Wind River Indian Reservation Boundary, U.S. Environmental Protection Agency, 6-Dec-12, page 9.
[43] Ibid., page 72.

> stabilized. Surface remedial action at the Riverton site was completed in November 1989.[44]

And:

> The Riverton mill site is about two and one-half miles southwest of the center of the town of Riverton, and is located on fee land within the Wind River Indian Reservation. Fremont Minerals, Inc. began operations at the site in 1958. The mill was later purchased by Susquehanna-Western, Inc., and milling operations ended in June, 1963. The nominal capacity of the mill was 550 tons per day, and about 910,000 tons of tailings were generated. Based on the average grade of the ore processed, the tailings have a calculated average radium-226 concentration of about 660 pCi/gram, and the total radium content of the pile is estimated at about 500 Curies (PHS, 1970; radium data from USAEC Division of Occupational Safety).
>
> The main mill building was partially dismantled in the early 1970's and most of the equipment was salvaged. Western Nuclear, Inc. is currently using some of the remaining facilities at the site to produce sulfuric acid which is used at operating uranium mills in the Gas Hills area.

The original tailings pond and pile covered about 40 acres. In 1972, Susquehanna-Western stabilized the tailings pile. The pile was rearranged to cover about 80 acres, fenced, and covered with a layer of clean material. The cover material was obtained from the immediate vicinity of the pile, and ranges from coarse gravel to the local topsoil. Clean fill was also placed on a portion of the ore storage yard northeast of the mill buildings. The covered pile was apparently seeded, but at the time of a survey in 1977, there was very little established vegetation on the pile. Bare tailings were visible at a few spots on the pile, and along most of the fence around the perimeter.[45]

On November 8, 1978 the U.S. Congress enacted the Uranium Mill Tailings Radiation Control Act (UMTRCA), which produced explicit standards for the surface conditions of retired sites as well as ground water conditions. The Fremont Metals site was remediated as an UMTRCA site until 1992.

[44] Final Programmatic Environmental Impact Statement for the Uranium Mill Tailings Remedial Action Ground Water Project Volume I, United States Department of Energy, 1-Oct-1996, page 3-34.
[45] Radiological Survey at the Inactive Uranium Mill Site near Riverton, Wyoming, U.S. EPA, Jun-1977, pp 1-2.

In 1995, the U.S. Department of Energy determined that additional groundwater contamination had occurred in the area. Steps were then taken to protect local inhabitants, many of whom were aboriginal residents of the area. Then, in 2010, a flood in the nearby river raised contamination levels ten-fold. Today, continuing litigation regarding responsibility for remediation is taking place between the state, the U.S. Federal authorities, and the aboriginal peoples.

The history of the Riverton tailings site is not a positive one. Fifty years after the plant ceased its operations, the site is still in active remediation. Site monitoring is expected to continue for the next hundred years. State, local, and national responsibilities have been poorly defined and conflict is frequent. At different times the U.S. Department of Energy (DOE), the U.S. Environmental Protection Agency (EPA), the U.S. Department of the Interior, and the Nuclear Regulatory Commission (NRC) have taken active roles. Litigation is currently underway between the EPA, the Wind River Indian Reservation, and the State of Wyoming concerning environmental responsibilities in the Riverton area.[46]

The Riverton story is likely a good forecast of future uranium tailings remediation and monitoring in northern Quebec if the long-term issues that exist there are not specifically addressed at the outset. Given major uncertainties in the changing climate and hydrology of northern Quebec and the market for uranium, the planning process is unlikely to be straightforward or easy.

According to Strateco, little time and effort was put into considering a specific remediation plan for the Matoush site, and a more thorough investigation of future costs would be undertaken only after approval of their license. The plan that they proposed is roughly equivalent to the original remediation at Riverton.[47]

Surface Remediation at Riverton

In 1975, a radiological survey of the land surrounding the 80 acre tailings pile found that a total of about 460 additional acres were contaminated. However, if an area of 30 acres were to be decontaminated, the maximum residual exposure rate could be reduced to 40 μR (micro-Roentgens)/hour. Alternatively, if an area of 99 acres were

[46] Letter from Shaun McGrath to Governor Matt Mead, U.S. Environmental Protection Agency, 14-Feb-2014.
[47] Updated Preliminary Assessment of the Matoush Project, Scott Wilson Mining, 9-Apr-2010, pages 18-18 through 18-30.

to be decontaminated, the maximum residual exposure rate could be reduced to 10 μR/hour.[48] There is no mention of cost in the survey.

On November 8, 1978, explicit standards for the surface conditions of retired sites, as well as groundwater conditions, came into force under the Uranium Mill Tailings Radiation Control Act (UMTRCA). The standards for surface conditions are outlined here:

DOE/AL/62350-35F
REV. 1, VER. 1

URANIUM MILL TAILINGS REMEDIAL ACTION
(UMTRA) SURFACE PROJECT PLAN

ATTACHMENT 2

SUMMARY OF UMTRA SURFACE PROJECT EPA STANDARDS

Activity	Standard
Control of Tailings Piles	Control must be designed
Longevity	To be effective up to 1000 years, but not less than 200 years
Radon Emission	Not to exceed average release rate of 20 pCi per square meter per second, OR not increase the annual average concentration by more than 0.5 pCi per liter
Ground Water Protection	To meet 1987 proposed standards revised in 1990 (under EPA review)
Cleanup of Buildings	
Indoor Radon Decay Products	Concentration caused by tailings must not exceed 0.03 WL; however, the objective is that concentration caused by tailings does not exceed 0.02 WL
Indoor Gamma Protection	Not to exceed background level by more than 20 microentgens per hour
Cleanup of Land	Concentration of radium-226 in land averaged over any area of 100 square meters shall not exceed background by more than
Surface	- 5 pCi per gram, averaged over the first 15 cm of soil below the surface, AND
Buried	- 15 pCi per gram averaged over 15-cm thick layers more than 15 cm below the surface.

pCi - picocuries.
WL - working level.
cm - centimeter.

AUGUST 11, 1993
DOC06F3.ATA

ATTACHMENT 2

Figure 11 – UMTRA Surface Project EPA Standards

Surface cleanup occurred at Riverton from 1988 to 1992 at costs estimated around $43.1 million.[49] An estimate in 2004 of the surface remediation cost was $12.76/lb. At current prices, this is equivalent to nearly 40% of the U308 sales price. The following chart shows that this cost of cleanup is by no means out of the ordinary:

---

[48] Radiological Survey at the Inactive Uranium Mill Site near Riverton, Wyoming, US EPA, Jun-1977, page 21.
[49] Uranium Mill Tailings Remedial Action (UMTRA) Surface Project, US Department of Energy, August 1993. Retrieved 8/20/2014 @ http://www.osti.gov/scitech/servlets/purl/10185841

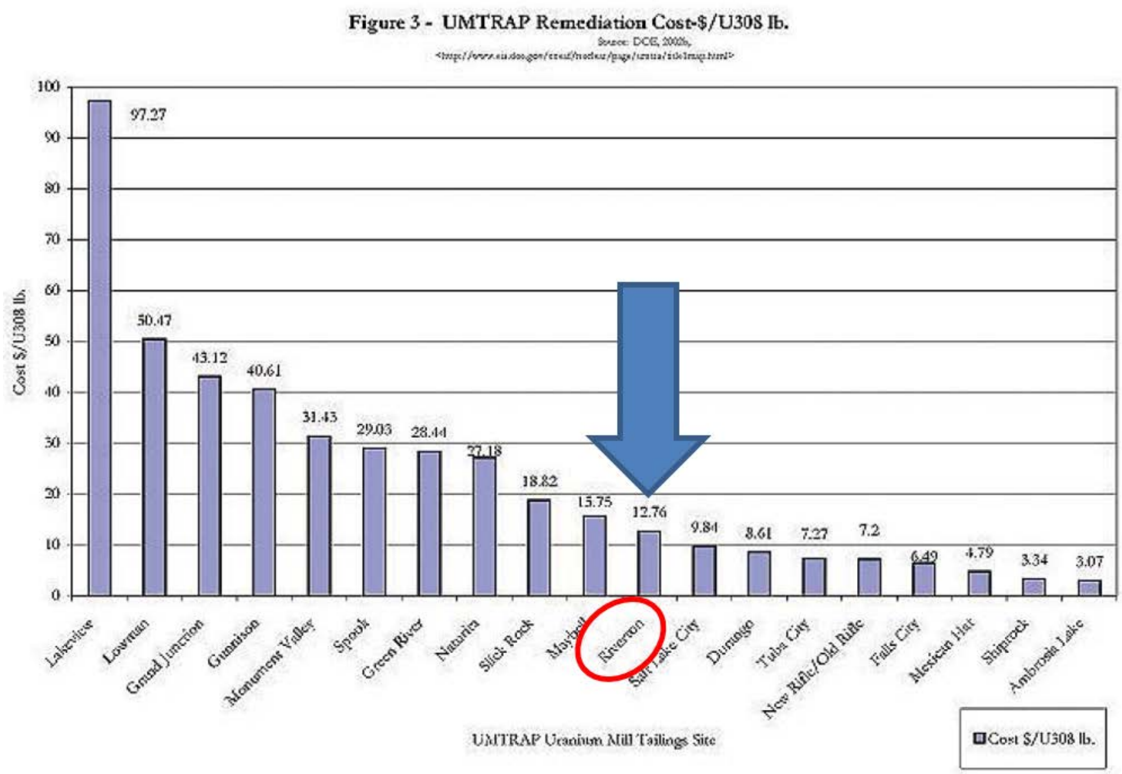


Figure 12 – Remediation Costs: $/U3O8 lb

Groundwater Remediation at Riverton

Following the surface remediation, the DOE prepared a "Baseline Risk Assessment of Ground Water Contamination at the Uranium Mill Tailings Site near Riverton, Wyoming" in September 1995.[50] According to the study:

> The Uranium Mill Tailings Remedial Action (UMTRA) Project consists of two phases: the Surface Project and the Ground Water Project. […]
>
> The UMTRA Project's second phase, the Ground Water Project, will evaluate the nature and extent of ground water contamination at the Riverton site that has resulted from the uranium ore processing activities. […] Exposure could hypothetically occur if drinking water were pumped from a well drilled in an area where ground water contamina-

[50] Baseline Risk Assessment of Ground Water Contamination at the Uranium Mill Tailings Site near Riverton, Wyoming, US Department of Energy, Sep-1995.

> tion might have occurred. Human health and environmental risks may also result if people, plants, or animals are exposed to surface water that has mixed with contaminated ground water.[51]

Due to the remote nature of the site, the DOE's baseline assessment only led to recommendations of further monitoring of the nearby Little Wind River for contamination by arsenic, manganese, molybdenum, sulfate, and uranium, all of which had been found in an aquifer between the site and the river. The DOE concluded that:[52]

> The levels of arsenic, manganese, molybdenum, sulfate, and uranium in the surficial aquifer between the former processing site and the Little Wind River could be associated with adverse health effects if the ground water is used for drinking in the future; therefore, ground water from the contaminated portion of the aquifer should not be used until the water quality improves.
>
> Monitoring ground water from the unconfined surficial aquifer, the semiconfined aquifer, and potential surface expression points should continue until detailed characterization of the site ground water is complete. Monitoring the Little Wind River, including sampling during a low-flow period, may be desirable to assess the potential impact of contaminated floodplain ground water on river water quality.[53]

The next year, the DOE prepared an Environmental Impact Statement which described the Department's preferred course of action as being one in which the most passive remediation deemed "protective of human health and the environment" would be selected. Following this approach, the DOE first considered a strategy of "no remediation and proceeding if necessary" as well as a strategy of "natural flushing" with monitoring and institutional controls. The DOE indicated that more complex methods such as water pumping and treatment would only be considered if passive methods were deemed insufficient in a site risk assessment and site observational work plan.[54]

[51] Ibid., page CS-1.
[52] Ibid., page 8-2.
[53] Ibid., page 8-6.
[54] Final Programmatic Environmental Impact Statement for the Uranium Mill Tailings Remedial Action Ground Water Project, Volume I, Oct-1996, page Sum-2.

Applying this approach, no active steps toward remediation were deemed required by the DOE. Instead, the DOE adopted a policy of "natural flushing", as well as a 100-year active monitoring period. The following map shows the scale of the monitoring effort.[55]

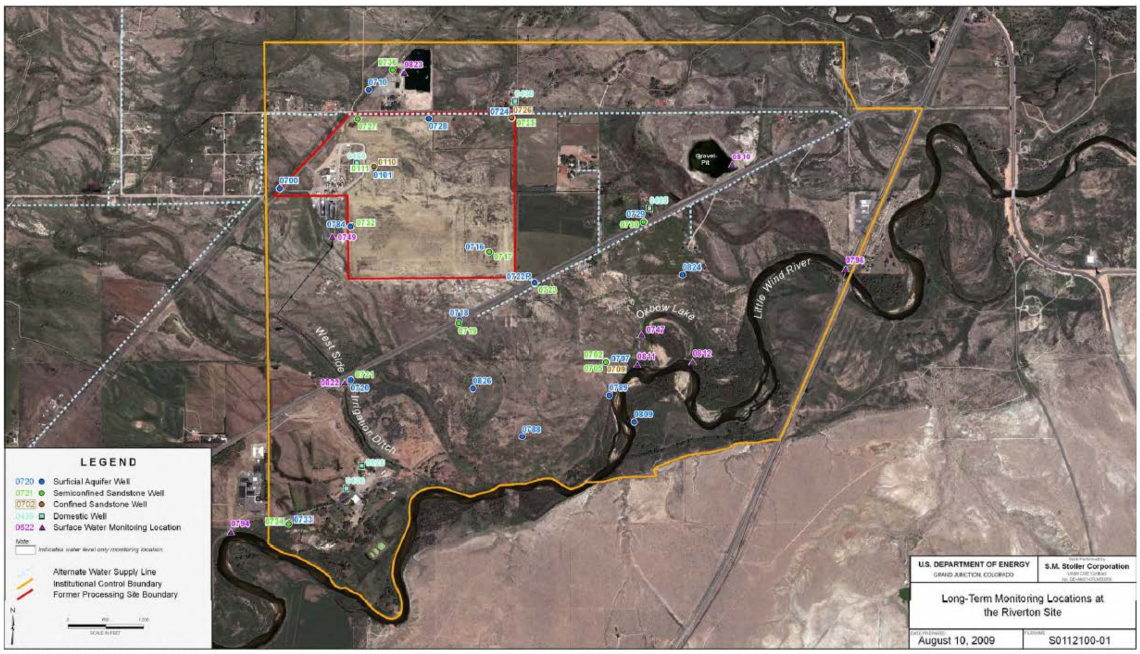


Figure 13 – Map of Riverton Remediation Area

Groundwater nearby is contaminated, and an alternate water supply system was agreed to by the local tribes in 1998 which was intended to provide residents with a safe water source during the 100-year extended groundwater cleanup period. The system was set up incompletely at first, spurring complaints from locals that no steps were taken to ensure homes were connected to the alternative water supply. Elevated levels of uranium and radionuclides were detected in the alternative drinking supply in 2003 and 2011.[56,57]

According to the DOE, Riverton was expected to naturally clean itself of pollutants during the 100-year cleanup and monitoring period after its closure, that is, by 2089.

[55] Long-Term Management Plan for the Riverton, Wyoming, Processing Site, US Department of Energy, Sep-2009, page 7.
[56] News Release: DOE Announces Riverton Water Sampling Results. Energy.gov. 11 May 2012.
[57] Shoshone & Arapaho Tribes Joint Business Council. Letter to Secretary of Energy Spencer Abraham. 9, Oct. 2003.

However, after a flood in 2010, uranium and molybdenum concentration levels in the surrounding groundwater spiked, which necessitated further evaluation of the effectiveness of passive remediation (natural flushing).[58] The EPA became involved because of possible violations of the *Safe Drinking Water Act* and the *Clean Water Act*.[59]

Evidently, the 2089 regulatory deadline is unlikely to be met using the chosen "natural flushing" strategy. In 2012, the Wyoming State Senate passed a Joint Resolution requesting money from the federal government for cleanup of the site on the Wind River Reservation.[60,61]

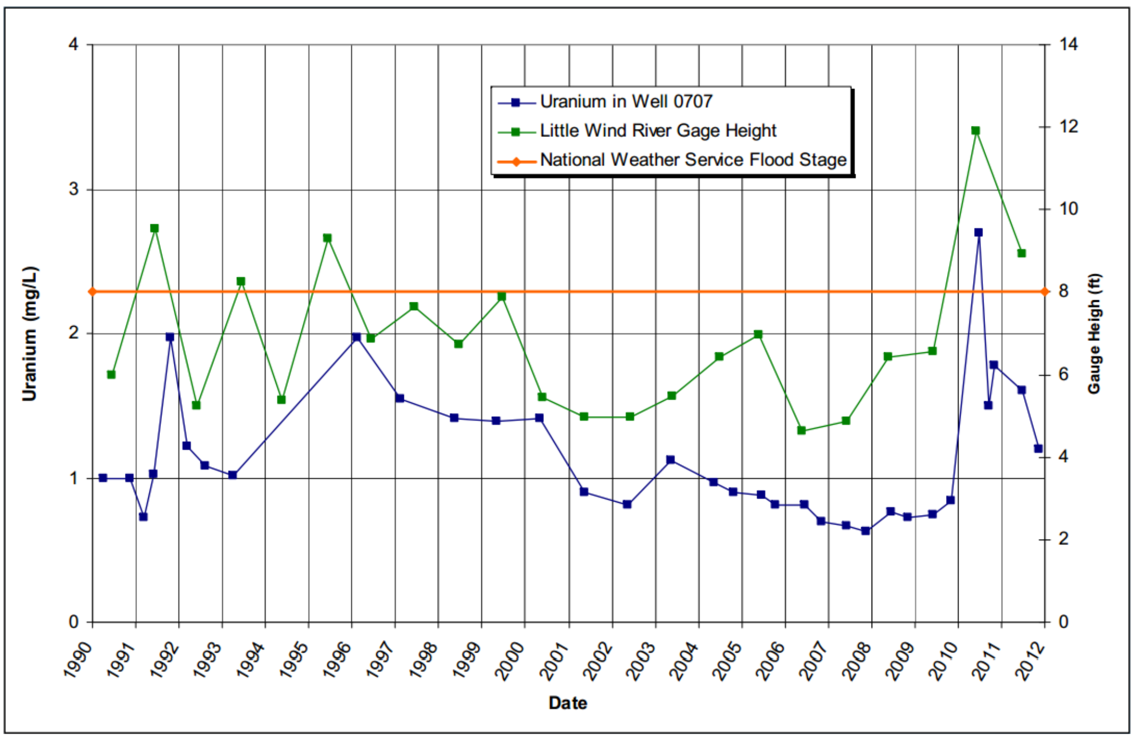


Figure 14 – Riverton: Varying Uranium Levels Over Time

58 State of Wyoming. Senate Joint Resolution No. SJ0002. 2012. http://legisweb.state.wy.us/2012/Introduced/SJ0002.pdf
59 Wind River Environmental Quality Commission. UMTRA Program- Phase II Groundwater/Drinking Water Final Report. 30 Sep. 2003, page 13.
60 Beck, Bob. Senate Gives Approval to Funding for Uranium Cleanup. Wyoming Public Media. 24 Feb. 2012.
61 Status and Planned Actions at the Riverton, Wyoming, Uranium Mill Tailing Radiation Control Act (UMTRCA) Title I Site, US DOE, 2-May-2012, page 14.

In 2013, however, measured concentrations returned to their pre-flood levels.[62] The report from which these findings are taken states that annual sampling will now be taken each September, when maximum surface water concentrations occur. Regarding the existing "natural flushing" strategy, the report says:

> Several types of information, including uranium mobilized by flood events, current plume size and concentration, groundwater modeling results, historical data, and experience at other Uranium Mill Tailings Radiation Control Act sites, indicates natural flushing of the surficial aquifer is occurring at the Riverton site, but the rate at which it is occurring might not meet the 100-year regulatory time frame. Additional information will be needed and additional work conducted to gain a better understanding of the site before a final decision can be made regarding the natural flushing compliance strategy or before a selection of an alternate compliance strategy can be made.[63]

[62] 2013 Verification Monitoring Report, Riverton, WY Processing Site. US Department of Energy, Legacy Management, 1-Apr-2014, page 20.
[63] 2013 Verification Monitoring Report, Riverton, WY Processing Site, US Department of Energy, Legacy Management, 1-Apr-2014, page v.

V. Appendices

Appendix A: Robert McCullough's Professional Vita

Robert McCullough

Principal
McCullough Research, 3816 S.E. Woodstock Place, Portland, OR 97202 USA

Professional Experience

1985-present	Principal, McCullough Research: provide strategic planning assistance, litigation support, and planning for a variety of customers in energy, regulation, and primary metals
1996-present	Adjunct Professor, Economics, Portland State University
1990-1991	Director of Special Projects and Assistant to the Chairman of the Board, Portland General Corporation: conducted special assignments for the Chairman in the areas of power supply, regulation, and strategic planning
1988-1990	Vice President in Portland General Corporation's bulk power marketing utility subsidiary, Portland General Exchange: primary negotiator on the purchase of 550 MW transmission and capacity package from Bonneville Power Administration; primary negotiator of PGX/M, PGC's joint venture to establish a bulk power marketing entity in the Midwest; negotiated power contracts for both supply and sales; coordinated research function
1987-1988	Manager of Financial Analysis, Portland General Corporation: responsible for M&A analysis, restructuring planning, and research support for the financial function; reported directly to the CEO on the establishment of Portland General Exchange; team member of PGC's acquisitions task force; coordinated PGC's strategic planning process; transferred to the officer's merit program as a critical corporate manager

1981-1987	Manager of Regulatory Finance, Portland General Electric: responsible for a broad range of regulatory and planning areas, including preparation and presentation of PGE's financial testimony in rate cases in 1980, 1981, 1982, 1983, 1985, and 1987 before the Oregon Public Utilities Commission; responsible for preparation and presentation of PGE's wholesale rate case with Bonneville Power Administration in 1980, 1981, 1982, 1983, 1985, and 1987; coordinated activities at BPA and FERC on wholesale matters for the InterCompany Pool (the association of investor-owned utilities in the Pacific Northwest) since 1983; created BPA's innovative aluminum tariffs (adopted by BPA in 1986); led PGC activities, reporting directly to the CEO and CFO on a number of special activities, including litigation and negotiations concerning WPPSS, the Northwest Regional Planning Council, various electoral initiatives, and the development of specific tariffs for major industrial customers; member of the Washington Governor's Task Force on the Vancouver Smelter (1987) and the Washington Governor's Task Force on WPPSS (Washington Public Power Supply System, nuclear plants 1-5) Refinancing (1985); member of the Oregon Governor's Work Group On Extra-Regional Sales (1983); member of the Advisory Committee to the Northwest Regional Planning Council (1981)
1979-1980	Economist, Rates and Revenues Department, Portland General Electric: responsible for financial and economic testimony in the 1980 general case; coordinated testimony in support of the creation of the DRPA (Domestic and Rural Power Authority) and was a witness in opposition to the creation of the Columbia Public Utility District in state court; member of the Scientific and Advisory Committee to the Northwest Regional Power Planning Council

Economic Consulting

2014	Advisor to the Grand Council of the Crees on uranium mining in Quebec
2014	Support for the investigation of Barclays Bank

2013	Advisor to Environmental Defense Fund on gasoline and oil issues in California
2013	Advisor to Energy Foundation on Ohio competitive issues
2013	Export market review in the Maritime Link proceeding
2013	Retained to do a business case analysis of the Columbia Generating Station nuclear plant by the Physicians for Social Responsibility
2011	Consultant to Citizens Action Coalition of Indiana on Indiana Gasification LLC project
2010-present	Analysis and expert witness testimony for Block Island Intervenors concerning Deepwater offshore wind project
2010	Analysis for Eastern Environmental Law Center of 25 closed cycle plants in New York State
2010	Advisor on BPA transmission line right of way issues
2009-2010	Advisor to Gamesa USA on a marketing plan to promote a wind farm in the Pacific Northwest
2009-2010	Expert witness in City of Alexandria vs. Cleco
2009-present	Expert witness in City of Beaumont v. Entergy
2008-2009	Consultant to AARP Connecticut and Texas chapters on the need for a state power authority (Connecticut) and balancing energy services (Texas)
2008-present	Advisor to the American Public Power Association on administered markets
2008	Expert witness on trading and derivative issues in Barrick Gold litigation
2008-present	Advisor to Jackson family in Pelton/Round Butte dispute

2006-present	Advisor to the Illinois Attorney General on electric restructuring issues
2006-present	Expert witness for Lloyd's of London in SECLP insurance litigation
2006-2007	Advisor to the City of Portland in the investigation of Portland General Electric
2005-2006	Expert witness for Antara Resources in Enron litigation
2005-2006	Advisor to Utility Choice Electric
2005-2007	Expert witness for Federated Rural Electric Insurance Company and TIG Insurance in Cowlitz insurance litigation
2005-2007	Advisor to Gray's Harbor PUD on market manipulation
2005-2007	Advisor to the Montana Attorney General on market manipulation
2004-2005	Expert witness for Factory Mutual in Northwest Aluminum litigation
2004	Advisor to the Oregon Department of Justice on market manipulation
2003-2006	Expert witness for Texas Commercial Energy
2003-2004	Advisor to The Energy Authority
2002-2005	Advisor to the U.S. Department of Justice on market manipulation issues
2002-2004	Expert witness for Alcan in Powerex arbitration
2002-2003	Expert witness for Overton Power in IdaCorp Energy litigation
2002-2003	Expert witness for Stanislaus Food Products
2002	Advisor to VHA Pennsylvania on power purchasing

2002	Expert witness for Sierra Pacific in Enron litigation
2002-2004	Advisor to U.S. Department of Justice
2002-2007	Expert witness for Snohomish PUD in Enron litigation
2002-1010	Expert witness for Snohomish in Morgan Stanley investigation
2001-2005	Advisor to Nordstrom
2001-2005	Advisor to Steelscape Steel on power issues in Washington and California
2001-2008	Advisor to VHA Southwest on power purchasing
2001-present	Expert witness for City of Seattle, Seattle City Light and City of Tacoma in FERC's EL01-10 refund proceeding
2001	Advisor to California Steel on power purchasing
2001	Advisor to the California Attorney General on market manipulations in the Western Systems Coordinating Council power markets
2000-present	Expert witness for Wah Chang in PacifiCorp litigation
2000-2001	Expert witness for Southern California Edison in Bonneville Power Administration litigation
2000-2001	Advisor to Blue Heron Paper on West Coast price spikes
2000	Expert witness for Georgia Pacific and Bellingham Cold Storage in the Washington Utilities and Transportation Commission's proceeding on power costs
1999	Expert report for the Center Helios on Freedom of Information in Québec
1999-2002	Advisor to Bayou Steel on alternative energy resources

1999-2000	Expert witness for the Large Customer Group in PacifiCorp's general rate case
1999-2000	Expert witness for Tacoma Utilities in WAPA litigation
1999-2000	Advisor for Nucor Steel and Geneva Steel on PacifiCorp's power costs
1999-2000	Advisor to Abitibi-Consolidated on energy supply issues
1999	Advisor to GTE regarding Internet access in competitive telecommunication markets
1999	Advisor to Logansport Municipal Utilities
1998-2001	Advisor to Edmonton Power on utility plant divestiture in Alberta
1998-2001	Energy advisor for Boise Cascade
1998-2000	Advisor to California Steel on power purchasing
1998-2000	Advisor to Nucor Steel on power purchasing and transmission negotiations
1998-2000	Advisor to Cominco Metals on the sale of hydroelectric dams in British Columbia
1998-2000	Advisor to the Betsiamites on the purchase of hydroelectric dams in Québec
1998-1999	Advisor to the Illinois Chamber of Commerce concerning the affiliate electric and gas program
1998	Intervention in Québec's first regulatory proceeding on behalf of the Grand Council of the Crees
1998	Market forecasts for Montana Power's restructuring proceeding
1997-1999	Advisor to the Columbia River Intertribal Fish Commission on Columbia fish and wildlife issues

1997-1998	Advisor to Port of Morrow regarding power marketing with respect to existing gas turbine plant
1997-1998	Expert witness for Tenaska in BPA litigation
1997	Advisor to Kansai Electric on restructuring in the electric power industry (with emphasis on the California markets)
1997-2004	Expert witness for Alcan in BC Hydro litigation
1996-1997	Bulk power purchasing for the Association of Bay Area Cities
1996-1997	Advisor to Texas Utilities on industrial issues
1996-1997	Expert witness for March Point Cogeneration in Puget Sound Power and Light litigation
1996	Advisor to Longview Fibre on contract issues
1995-present	Bulk power supplier for several Pacific Northwest industrials
1995-1997	Advisor to Tacoma Utilities on contract issues
1995-1999	Advisor to Seattle City Light on industrial contract issues
1995-1996	Expert witness for Tacoma Utilities in WAPA litigation
1994-1995	Advisor to Idaho Power on Southwest Intertie Project marketing
1993-2001	Northwest representative for Edmonton Power
1993-1997	Expert witness for MagCorp in PacifiCorp litigation
1992-1995	Advisor to Citizens Energy Corporation
1992-1994	Negotiator on proposed Bonneville Power Administration aluminum contracts
1992	Bulk power marketing advisor to Public Service of Indiana

1997-2003	Advisor to the Manitoba Cree on energy issues in Manitoba, Minnesota and Québec; Advisor to the Grand Council of the Crees on hydroelectric development
1991-2000	Strategic advisor to the Chairman of the Board, Portland General Corporation
1991-1993	Chairman of the Investor Owned Utilities' (ICP) committee on BPA financial reform
1991-1992	Financial advisor on the Trojan nuclear plant owners' negotiation team
1991	Advisor to Shasta Dam PUD on the California Oregon Transmission Project and related issues
1990-1991	Advised the Chairman of the Illinois Commerce Commission on issues pertaining to the 1990 General Commonwealth Rate Proceeding; prepared an extensive analysis of the bulk power marketing prospects for Commonwealth in ECAR and MAIN
1988	Facilitated the settlement of Commonwealth Edison's 1987 general rate case and restructuring proposal for the Illinois Commerce Commission; reported directly to the Executive Director of the Commission; responsibilities included financial advice to the Commission and negotiations with Commonwealth and interveners
1987-1988	Created the variable aluminum tariff for Big Rivers Electric Corporation: responsibilities included testimony before the Kentucky Public Service Commission and negotiations with BREC's customers (the innovative variable tariff was adopted by the Commission in August 1987); supported negotiations with the REA in support of BREC's bailout debt restructuring
1981-1989	Consulting projects including: financial advice for the Oregon AFL-CIO; statistical analysis of equal opportunity for Oregon Bank; cost of capital for the James River dioxin review; and economic analysis of qualifying facilities for Washington Hydro Associates

1980-1986	Taught classes in senior and graduate forecasting, micro-economics, and energy at Portland State University

Education

Unfinished Ph.D.	Economics, Cornell University; Teaching Assistant in micro- and macro-economics
M.A.	Economics, Portland State University, 1975; Research Assistant
B.A.	Economics, Reed College, 1972; undergraduate thesis, "Eurodollar Credit Creation"

Areas of specialization include micro-economics, statistics, and finance

Papers and Publications

Forthcoming	"Nuclear Winter", *Electricity Journal* (upcoming)
July 2013	"Mid-Columbia Spot Markets and the Renewable Portfolio Standard", *Public Utilities Fortnightly*
April 14, 2013	"Selling Low and Buying High", *The Oregonian*
December 2012	"Are Electric Vehicles Actually Cost-Effective?", *Electricity Policy*
November 30, 2012	"Portland's Energy Credits: The trouble with buying 'green'", *The Oregonian*
July 2009	"Fingerprinting the Invisible Hand", *Public Utilities Fortnightly*
February 2008	Co-author, "The High Cost of Restructuring", *Public Utilities Fortnightly*
March 27, 2006	Co-author, "A Decisive Time for LNG", *The Daily Astorian*
February 9, 2006	"Opening the Books", *The Oregonian*

August 2005	"Squeezing Scarcity from Abundance", *Public Utilities Fortnightly*
April 1, 2002	"The California Crisis: One Year Later", *Public Utilities Fortnightly*
March 13, 2002	"A Sudden Squall", *The Seattle Times*
March 1, 2002	"What the ISO Data Says About the Energy Crisis", *Energy User News*
February 1, 2001	"What Oregon Should Know About the ISO", *Public Utilities Fortnightly*
January 1, 2001	"Price Spike Tsunami: How Market Power Soaked California", *Public Utilities Fortnightly*
March 1999	"Winners & Losers in California", *Public Utilities Fortnightly*
July 15, 1998	"Are Customers Necessary?", *Public Utilities Fortnightly*
March 15, 1998	"Can Electricity Markets Work Without Capacity Prices?", *Public Utilities Fortnightly*
February 1998	"Coping With Interruptibility", *Energy Buyer*
January 1998	"Pondering the Power Exchange", *Energy Buyer*
December 1997	"Getting There Is Half the Cost: How Much Is Transmission Service?", *Energy Buyer*
November 1997	"Is Capacity Dead?", *Energy Buyer*
October 1997	"Pacific Northwest: An Overview", *Energy Buyer*
August 1997	"A Primer on Price Volatility", *Energy Buyer*
June 1997	"A Revisionist's History of the Future", *Energy Buyer*
Winter 1996	"What Are We Waiting for?" *Megawatt Markets*

October 21, 1996	"Trading on the Index: Spot Markets and Price Spreads in the Western Interconnection", *Public Utilities Fortnightly*

McCullough Research Reports

December 11, 2013	"Economic Analysis of the Columbia Generating Station"
February 21, 2013	"McCullough Research Rebuttal to Western States Petroleum Association"
November 15, 2012	"May and October 2012 Gasoline Price Spikes on the West Coast"
June 5, 2012	"Analysis of West Coast Gasoline Prices"
October 3, 2011	"Lowering Florida's Electricity Prices"
July 14, 2011	"2011 ERCOT Blackouts and Emergencies"
March 1, 2010	"Translation" of the September 29, 2008 NY Risk Consultant's Hydraulics Report to Manitoba Hydro CEO Bob Brennan
December 2, 2009	"Review of the ICF Report on Manitoba Hydro Export Sales"
June 5, 2009	"New York State Electricity Plants' Profitability Results"
May 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas"
April 7, 2009	"A Forensic Analysis of Pickens' Peak: Speculation, Fundamentals or Market Structure"
March 30, 2009	"New Yorkers Lost $2.2 Billion Because of NYISO Practices"
March 3, 2009	"The New York Independent System Operator's Market-Clearing Price Auction is Too Expensive for New York"

February 24, 2009	“The Need for a Connecticut Power Authority”
January 7, 2009	“Review of the ERCOT December 18, 2008 Nodal Cost Benefit Study”
August 6, 2008	“Seeking the Causes of the July 3rd Spike in World Oil Prices” (updated September 16, 2008)
April 7, 2008	“Kaye Scholer’s Redacted ‘Analysis of Possible Complaints Relating to Maryland’s SOS Auctions’”
February 1, 2008	“Some Observations on Societe Generale’s Risk Controls”
June 26, 2007	“Looking for the ‘Voom’: A Rebuttal to Dr. Hogan’s ‘Acting in Time: Regulating Wholesale Electricity Markets’”
September 26, 2006	“Did Amaranth Advisors, LLC Attempt to Corner the March 2007 NYMEX at Henry Hub?”
May 18, 2006	“Developing a Power Purchase/Fuel Supply Portfolio: Energy Strategies for Cities and Other Public Agencies”
April 12, 2005	“When Oil Prices Rise, Using More Ethanol Helps Save Money at the Gas Pump”
April 12, 2005	“When Farmers Outperform Sheiks: Why Adding Ethanol to the U.S. Fuel Mix Makes Sense in a $50-Plus/Barrel Oil Market”
April 12, 2005	“Enron’s Per Se Anti-Trust Activities in New York”
February 15, 2005	“Employment Impacts of Shifting BPA to Market Pricing”
June 28, 2004	“Reading Enron’s Scheme Accounting Materials”
June 5, 2004	“ERCOT BES Event”
August 14, 2003	“Fat Boy Report”
May 16, 2003	“CERA Decision Brief”
January 16, 2003	“California Electricity Price Spikes”

November 29, 2002	"C66 and Artificial Congestion Transmission in January 2001"
August 17, 2002	"Three Days of Crisis at the California ISO"
July 9, 2002	"Market Efficiencies"
June 26, 2002	"Senate Fact Sheet"
June 5, 2002	"Congestion Manipulation"
May 5, 2002	"Enron's Workout Plan"
March 31, 2002	"A History of LJM2"
February 2, 2002	"Understanding LJM"
January 22, 2002	"Understanding Whitewing"

Testimony and Comment

November 15, 2012	Testimony before the California State Senate Select Committee on Bay Area Transportation on West Coast gasoline price spikes in 2012
July 20, 2010	Testimony before the Rhode Island Public Utility Commission on the Deepwater offshore wind project
April 7, 2009	Testimony before the U.S. Senate Committee on Energy and Natural Resources on "Pickens' Peak"
March 5, 2009	Testimony before the New York Assembly Committee on Corporations, Authorities and Commissions, and the Assembly Committee on Energy, "New York Independent System Operators Market Clearing Price Auction is Too Expensive for New York"

February 24, 2009	Testimony before the Energy and Technology Committee, Connecticut General Assembly, "An Act Establishing a Public Power Authority" on behalf of AARP
September 16, 2008	Testimony before the U.S. Senate Committee on Energy and Natural Resources, "Depending On 19th Century Regulatory Institutions to Handle 21st Century Markets"
January 7, 2008	Supplemental Comment ("The Missing Benchmark in Electricity Deregulation") before the Federal Energy Regulatory Commission on behalf of American Public Power Association, Docket Nos. RM07-19-000 and AD07-7-000
August 7-8, 2007	Testimony before the Oregon Public Utility Commission on behalf of Wah Chang, Salem, Oregon, Docket No. UM 1002
February 23 and 26, 2007	Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180
October 2, 2006	Direct Testimony before the Régie de l'énergie, Gouvernement du Québec on behalf of the Grand Council of the Cree
August 22, 2006	Rebuttal Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
June 1, 2006	Expert Report on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. H-01-3624
May 8, 2006	Testimony before the U.S. Senate Democratic Policy Committee, "Regulation and Forward Markets: Lessons from Enron and the Western Market Crisis of 2000-2001"
December 15, 2005	Direct Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
December 14, 2005	Deposition before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG

	Insurance Company v. Public Utility District No. 1 of Cowlitz County, No. 04-5052RBL
December 4, 2005	Expert Report on behalf of Utility Choice Electric in Civil Action No. 4:05-CV-00573
July 27, 2005	Expert Report before the United States District Court Western District of Washington at Tacoma on behalf of Federated Rural Electric Insurance Exchange and TIG Insurance Company, Federated Rural Electric Insurance Exchange and TIG Insurance Company v. Public Utility District No. 1 of Cowlitz County, Docket No. CV04-5052RBL
May 6, 2005	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
May 1, 2005	Rebuttal Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
March 24-25, 2005	Deposition by Enron Power Marketing, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
February 14, 2005	Expert Report on behalf of Factory Mutual, Factory Mutual v. Northwest Aluminum
January 27, 2005	Supplemental Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL03-180, et al.
April 14, 2004	Deposition by Enron Power Marketing, Inc. and Enron Energy Services before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
April 10, 2004	Rebuttal Testimony on behalf of the Office of City and County Attorneys, San Francisco, California, City and County Attorneys, San Francisco, California v. Turlock Irrigation District, Non-Binding Arbitration

February 24, 2004	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No.EL03-180, et al.
March 20, 2003	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of the City of Seattle, Washington, Docket No. EL01-10, et al.
March 11-13, 2003	Deposition by IdaCorp Energy L.P. before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
March 3, 2003	Expert Report before the District Court of the Fourth Judicial District of the State of Idaho on behalf of Overton Power District No. 5, State of Nevada, IdaCorp Energy L.P. v. Overton Power District No. 5, Case No. OC 0107870D
February 27, 2003	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington and the Port of Seattle, Washington, Docket No. EL01-10-005
October 7, 2002	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
October 2002	Expert Report before the Circuit Court of the State of Oregon for the County of Multnomah on behalf of Alcan, Inc., Alcan, Inc. v. Powerex Corp., Case No. 50 198 T161 02
September 27, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
August 8-9, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.

August 8, 2002	Deposition by Morgan Stanley Capital Group, Inc. before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 28, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of the City of Tacoma, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Public Utility District No. 1 of Snohomish County, Washington, Docket No. EL02-26, et al.
June 25, 2002	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Nevada Power Company and Sierra Pacific Power Company, Docket No. EL02-26, et al.
May 6, 2002	Rebuttal Testimony before the Public Service Commission of Utah on behalf of Magnesium Corporation of America in the Matter of the Petition of Magnesium Corporation of America to Require PacifiCorp to Purchase Power from MagCorp and to Establish Avoided Cost Rates, Docket No. 02-035-02
April 11, 2002	Testimony before the U.S. Senate Committee on Commerce, Science and Transportation, Washington DC
February 13, 2002	Testimony before the U.S. House of Representatives Sub-committee on Energy and Air Quality, Washington DC
January 29, 2002	Testimony before the U.S. Senate Committee on Energy and Natural Resources, Washington DC
August 30, 2001	Rebuttal Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10
August 16, 2001	Direct Testimony before the Federal Energy Regulatory Commission on behalf of Seattle City Light, Docket No. EL01-10

June 12, 2001	Rebuttal Testimony before the Public Utility Commission of the State of Oregon on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
April 17, 2001	Before the Public Utility Commission of the State of Oregon, Direct Testimony on behalf of Wah Chang, Wah Chang v. PacifiCorp in Docket UM 1002
March 17, 2000	Rebuttal Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10
February 1, 2000	Direct Testimony before the Public Service Commission of Utah on behalf of the Large Customer Group in the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulations, Docket No. 99-035-10

Presentations

May 6, 2014	"Economic Analysis of the Columbia Generating Station", Energy Northwest, Boise, Idaho
April 30, 2014	"Economic Analysis of the Columbia Generating Station", Portland State University, Portland, Oregon
April 22, 2014	"Economic Analysis of the Columbia Generating Station", Clark County, Vancouver, Washington
January 9, 2014	"Economic Analysis of the Columbia Generating Station", Northwest Power & Conservation Council, Portland, Oregon
January 1, 2014	"Economic Analysis of the Columbia Generating Station", Bonneville Power Administration, Portland, Oregon
December 2, 2013	"Economic Analysis of the Columbia Generating Station", Skamania, Carson, Washington

December 1, 2013	"Peak Peddling: Has Portland Bicycling Reached the Top of the Logistic Curve?" Oregon Transportation Research and Education Consortium, Portland, Oregon
July 12, 2013	"Economic Analysis of the Columbia Generating Station", Tacoma, Washington
June 21, 2013	"Economic Analysis of the Columbia Generating Station", Seattle City Light, Seattle, Washington
January 29, 2013	"J.D. Ross (Who)", Portland Rotary Club, Portland, Oregon.
January 13, 2011	"Estimating the Consumer's Burden from Administered Markets", American Public Power Association conference, Washington, DC
October 15, 2009	"The Mysterious New York Market", EPIS, Tucson, Arizona
October 14, 2009	"Do ISO Bidding Processes Result in Just and Reasonable Rates?", legal seminar, American Public Power Association, Savannah, Georgia
June 22, 2009	"Pickens' Peak Redux: Fundamentals, Speculation, or Market Structure", International Association for Energy Economics
June 5, 2009	"Transparency in ERCOT: A No-cost Strategy to Reduce Electricity Prices in Texas", Presentation at Texas Legislature
May 8, 2009	"Pickens' Peak", Economics Department, Portland State University
April 7, 2009	"Pickens' Peak: Speculators, Fundamentals, or Market Structure", 2009 EIA energy conference, Washington, DC
February 4, 2009	"Why We Need a Connecticut Power Authority", presentation to the Energy and Technology Committee, Connecticut General Assembly
October 28, 2008	"The Impact of a Volatile Economy on Energy Markets", NAESCO annual meeting, Santa Monica, California

April 1, 2008	"Connecticut Energy Policy: Critical Times…Critical Decisions", House Energy and Technology Committee, the Connecticut General Assembly
May 23, 2007	"Past Efforts and Future Prospects for Electricity Industry Restructuring: Why Is Competition So Expensive?", Portland State University
February 26, 2007	"Trust, But Verify", Take Back the Power Conference, National Press Club, Washington, DC
May 18, 2006	"Developing a Power Purchase/Fuel Supply Portfolio"
February 12, 2005	"Northwest Job Impacts of BPA Market Rates"
January 5, 2005	"Why Has the Enron Crisis Taken So Long To Solve?", Public Power Council, Portland, Oregon
September 20, 2004	"Project Stanley and the Texas Market", Gulf Coast Energy Association, Austin, Texas
September 9, 2004	"Back to the New Market Basics", EPIS, White Salmon, Washington
June 8, 2004	"Caveat Emptor", ELCON West Coast Meeting, Oakland, California
June 9, 2004	"Enron Discovery in EL03-137/180"
March 31, 2004	"Governance and Performance", Public Power Council, Portland, Oregon
January 23, 2004	"Resource Choice", Law Seminars International, Seattle, Washington
January 17, 2003	"California Energy Price Spikes: The Factual Evidence", Law Seminars International Seattle, Washington
January 16, 2003	"The Purloined Agenda: Pursuing Competition in an Era of Secrecy, Guile, and Incompetence"

September 17, 2002	"Three Crisis Days", California Senate Select Committee, Sacramento, California
June 10, 2002	"Enron Schemes", California Senate Select Committee Sacramento, California
May 2, 2002	"One Hundred Years of Solitude"
March 21, 2002	"Enron's International Ventures", Oregon Bar International Law Committee, Portland, Oregon
March 19, 2002	"Coordinating West Coast Power Markets", GasMart, Reno, Nevada
March 19, 2002	"Sauron's Ring", GasMart, Reno, Nevada
January 25, 2002	"Deconstructing Enron's Collapse: Buying and Selling Electricity on The West Coast", Seattle, Washington
January 18, 2002	"Deconstructing Enron's Collapse", Economics Seminar, Portland State University
November 12, 2001	"Artifice or Reality", EPIS Energy Forecast Symposium, Skamania, Washington
October 24, 2001	"The Case of the Missing Crisis" Kennewick Rotary Club, Kennewick, Washington
August 18, 2001	"Preparing for the Next Decade"
June 26, 2001	"Examining the Outlook on Deregulation"
June 25, 2001	Presentation, Energy Purchasing Institute for International Research (IIR), Dallas, Texas
June 6, 2001	"New Horizons: Solutions for the 21st Century", Federal Energy Management-U.S. Department of Energy, Kansas City, Kansas
May 24, 2001	"Five Years"

May 10, 2001	"A Year in Purgatory", Utah Industrial Customers Symposium-Utah Association of Energy Users, Salt Lake City, Utah
May 1, 2001	"What to Expect in the Western Power Markets this Summer", Western Power Market Seminar, Denver, Colorado
April 23, 2001	"Emerging Markets for Natural Gas", West Coast Gas Conference, Portland, Oregon
April 18, 2001	"Demystifying the Influence of Regulatory Mandates on the Energy Economy" Marcus Evans Seminar, Denver, Colorado
April 4, 2001	"Perfect Storm", Regulatory Accounting Conference, Las Vegas, Nevada
March 21, 2001	"After the Storm 2001", Public Utility Seminar, Reno, Nevada
February 21, 2001	"Future Imperfect", Pacific Northwest Steel Association, Portland, Oregon
February 12, 2001	"Power Prices in 2000 through 2005", Northwest Agricultural Chillers, Bellingham, Washington
February 6, 2001	Presentation, Boise Cascade Management, Boise, Idaho
January 19, 2001	"Wholesale Pricing and Location of New Generation Buying and Selling Power in the Pacific Northwest", Seattle, Washington
October 26, 2000	"Tsunami: Market Prices since May 22nd", International Association of Refrigerated Warehouses, Los Vegas, California
October 11, 2000	"Tsunami: Market Prices since May 22nd", Price Spikes Symposium, Portland, Oregon
August 14, 2000	"Anatomy of a Corrupted Market", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 30, 2000	"Northwest Market Power", Governor Locke of Washington, Seattle, Washington

June 10, 2000	"Northwest Market Power", Oregon Public Utility Commission and Oregon State Energy Office, Salem, Oregon
June 5, 2000	"Northwest Market Power", Georgia Pacific Management
May 10, 2000	"Magnesium Corporation Developments", Utah Public Utilities Commission
May 5, 2000	"Northwest Power Developments", Georgia Pacific Management
January 12, 2000	"Northwest Reliability Issues", Oregon Public Utility Commission

Volunteer Positions

2013-Present	Eastmoreland Neighborhood Association, President
2013-Present	Southeast Uplift, Chair

Appendix B: Looking at a Small Mining Project in Quebec

The Matoush project, now on an indefinite hold, has been under development by Strateco Resources Inc. for a considerable period. Work on the project ceased soon after the release of the 2014 RBC report that indicated low U3O8 prices for the immediate future.

Since Matoush required outside financing, a number of detailed reports on this small-scale project are available through the Canadian financial reporting system. This allows a detailed review of the economics under a variety of assumptions.

In its forecasts, Strateco Resources assumed a rosy future in spite of the dramatic fall in U3O8 prices over recent years. The chart below tells the basic story: after a spike in 2007, oversupply has pushed U3O8 prices down to historically low prices. However, the pricing analysis in the Scott Wilson Mining scoping study regarding the Matoush project, which was prepared for Strateco in 2010, tends to gloss over the depressing market conditions without detailed analysis.[64] In projecting the financial viability of the project, the scoping study assumed a sale price of US$75 per pound. There is evidence of some concerns with the optimistic price assumption in the report although it is phrased very obliquely. The report clearly does not believe that the US $75 per pound price could have been realized in 2010.[65]

In 2012, RPA Inc. prepared an updated scoping study,[66] which is largely a rehashing of the original by Scott Wilson. The more recent study reports slightly higher amounts of uranium deposits, but still operates on the assumption of a US $75/lb selling price of the end product. The analysis that follows (Tables 2-4) is based on the former study, but is relevant to the Matoush project at all stages of planning. The costs of production that are reported by the 2010 Scott Wilson study show that if an internal rate of return of 15% is to be reached, then U3O8 must sell at a spot price of at least US $51/lb. If the project were to offer a return rate lower than 15%, it would

[64] Updated Preliminary Assessment, page 18-31.

[65] For example, page 20-3 says:

> Direct marketing of Matoush production is recommended. Assuming an environment of volatility in the spot market and an upward trend in long-term market prices, it would be prudent to adopt a contracting strategy which would allow at least 50% of production to be sold under medium- to long-term contracts three to four years ahead of the delivery year. The uncommitted production could then be sold either under long-term or spot market contracts closer to the years of delivery, depending on market conditions.

[66] http://www.stratecoinc.com/data/pdf/2012/RPAStratecoMatoushMemoDec42012Final.pdf

almost certainly not acquire financing, and so the project can safely be written off as economically unviable at all U3O8 prices lower than US $51/lb.

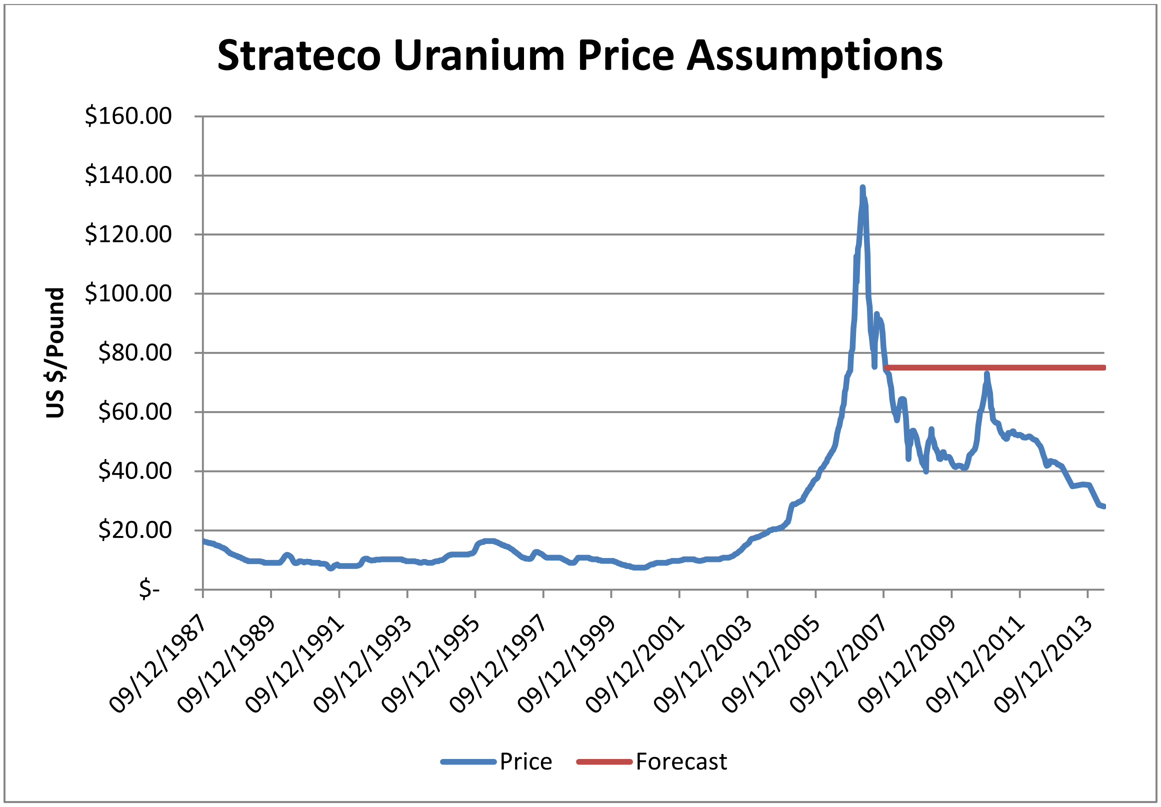


Figure 15 – Strateco Uranium Price Assumptions

In reality, since no one has a completely credible forecast of future U3O8 prices, the life and death of projects like Matoush depend on the ability to secure financing. When RBC lowered its forecast, it sounded the death knell for Matoush.

Matoush's position as of the RBC forecast of June 18, 2013 was precarious:[67]

[67] Metal Prospects Uranium Market Outlook – Third Quarter 2013. RBC, 18-Jun-2013, page 1.

YEAR			2015	2016	2017	2018	2019	2020	2021	2022	2023
PHYSICALS											
Ore Production		000t									
AM15 & MT34		%U3O8			169.8	240.6	132.7	130.4	118.8	23.5	
Grade		000t			0.64%	0.40%	0.44%	0.56%	0.64%	1.33%	0.00%
MT22		%U3O8			-	-	130	131.8	130.8	200.6	239.6
Grade					0.00%	0.00%	0.48%	0.48%	0.49%	0.40%	0.47%
Total		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%
Contained Metal		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30
Production Rate		tpd			485	688	750	749	713	640	685
METALLURGY											
Mill Feed		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%
Contained Metal		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30
Recovered Metal	97.60%	000lbs			2,333.90	2,073.20	2,604.90	2,946.50	3,010.90	2,392.40	2,413.00
REVENUE											
Metal Price	75	US$/lb			$80.00	$80.00	$80.00	$80.00	$65.00	$65.00	$65.00
Exchange Rate	0.85	US$/C$			0.9065	0.9093	0.9122	0.910298	0.9104713	0.9106445	0.9108177
Gross Revenue					$205,970	$182,400	$228,450	$258,948	$214,953	$170,765	$172,202
Transport	0.1	per lb			$233	$207	$260	$295	$301	$239	$241
Net Smelter Return (NSR)					$205,737	$182,192	$228,189	$258,654	$214,652	$170,526	$171,961
Royalty	2.00%				$4,115	$3,644	$4,564	$5,173	$4,293	$3,411	$3,439
NSR after Royalty					$201,622	$178,548	$223,626	$253,480	$210,359	$167,115	$168,522
OPERATI NG COSTS											
Mining		000C$			$26,676	$29,526	$28,983	$29,174	$28,129	$27,352	$25,157
Process		000C$			$28,193	$28,193	$28,193	$28,193	$28,193	$28,193	$28,193
Power		000C$			$10,875	$10,875	$10,875	$10,875	$10,875	$10,875	$10,875
Maintenance		000C$			$7,557	$7,557	$7,557	$7,557	$7,557	$7,557	$7,557
Site Services		000C$			$9,934	$9,934	$9,934	$9,934	$9,934	$9,934	$9,934
General and Administrative (G &A)		000C$			$6,818	$6,818	$6,818	$6,818	$6,818	$6,818	$6,818
Total		000C$			$90,052	$92,902	$92,359	$92,550	$91,506	$90,729	$88,533
OPERATING PROFIT					$111,570	$85,646	$131,267	$160,931	$118,853	$76,386	$79,989
CAPITAL COSTS											
Direct Capita l Costs											
Mine											
Total Direct Capital		000C$	$1,587	$58,312	$-	$-	$-	$-	$-	$-	$-
Indirect Capital Costs		000C$	$3,147	$61,260	$-	$-	$-	$-	$-	$-	$-
Contingency		000C$	$0	$0	$-	$-	$-	$-	$-	$-	$-
Capital Spares		000C$	$0	$1,210	$-	$-	$-	$-	$-	$-	$-
Sustaining Ca pital		000C$	$0	$0	$6,636	$5,686	$4,895	$3,809	$2,064	$1,598	$0
Closure			$0	$0							
Total Capital Costs		000C$	$17,571	$343,236	$6,636	$5,686	$4,895	$3,809	$2,064	$1,598	$0
		C$/lbU3O8									
PRE-TAX CASH FLOW		000C$	($17,571)	($343,236)	$104,934	$79,960	$126,372	$157,121	$116,789	$74,788	$79,989
Annual											
Cumulative			($14,836)	($292,830)	($166,152)	($63,461)	$86,184	$266,026	$453,597	$588,704	$728,528
INTERNAL RATE OF RETURN		%	21.3%								

Table 2 – Matoush Financials (2013)

The internal rate of return had fallen to 21.3%, barely above the 15% hurdle rate common in the industry. Further delays would have made the situation worse, since RBC also forecasted lower prices for U3O8 in 2021. An additional year of delay – very likely in the situation in Quebec – would lower the internal rate of return 2.4%.

Unfortunately, even RBC's 2013 forecast was too rosy.[68] The lower 2014 RBC forecast basically eliminated the viability of the project:

YEAR			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PHYSICALS												
Ore Production		000t										
AM15 & MT34		%U3O8			169.8	240.6	132.7	130.4	118.8	23.5		
Grade		000t			0.64%	0.40%	0.44%	0.56%	0.64%	1.33%	0.00%	
MT22		%U3O8			-	-	130	131.8	130.8	200.6	239.6	
Grade					0.00%	0.00%	0.48%	0.48%	0.49%	0.40%	0.47%	
Total		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6	
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%	
Contained Metal		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30	
Production Rate		tpd			485	688	750	749	713	640	685	
METALLURGY												
Mill Feed		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6	
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%	
Contained Metal		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30	
Recovered Metal	97.60%	000lbs			2,333.90	2,073.20	2,604.90	2,946.50	3,010.90	2,392.40	2,413.00	
REVENUE												
Metal Price	75	US$/lb			$40.00	$45.00	$50.00	$70.00	$80.00	$80.00	$80.00	
Exchange Rate	0.85	US$/C$			0.9065	0.9093	0.9122	0.910298	0.9104713	0.9106445	0.9108177	
Gross Revenue					$102,985	$102,600	$142,781	$226,580	$264,557	$210,172	$211,941	
Transport	0.1	per lb			$233	$207	$260	$295	$301	$239	$241	
Net Smelter Return (NSR)					$102,752	$102,392	$142,521	$226,285	$264,256	$209,933	$211,700	
Royalty	2.00%				$2,055	$2,048	$2,850	$4,526	$5,285	$4,199	$4,234	
NSR after Royalty					$100,697	$100,345	$139,670	$221,759	$258,971	$205,734	$207,466	
OPERATI NG COSTS												
Mining		000C$			$26,676	$29,526	$28,983	$29,174	$28,129	$27,352	$25,157	
Process		000C$			$28,193	$28,193	$28,193	$28,193	$28,193	$28,193	$28,193	
Power		000C$			$10,875	$10,875	$10,875	$10,875	$10,875	$10,875	$10,875	
Maintenance		000C$			$7,557	$7,557	$7,557	$7,557	$7,557	$7,557	$7,557	
Site Services		000C$			$9,934	$9,934	$9,934	$9,934	$9,934	$9,934	$9,934	
General and Administrative (G &A)		000C$			$6,818	$6,818	$6,818	$6,818	$6,818	$6,818	$6,818	
Total		000C$			$90,052	$92,902	$92,359	$92,550	$91,506	$90,729	$88,533	
		000C$			$38.58	$44.81	$35.46	$31.41	$30.39	$37.92	$36.69	
OPERATING PROFIT					$10,644	$7,442	$47,311	$129,209	$167,466	$115,005	$118,933	
CAPITAL COSTS												
Direct Capita l Costs												
Indirect Capital Costs		000C$	$3,147	$61,260	$-	$-	$-	$-	$-	$-	$-	$-
Contingency		000C$	$0	$0	$-	$-	$-	$-	$-	$-	$-	$-
Capital Spares		000C$	$0	$1,210	$-	$-	$-	$-	$-	$-	$-	$-
Sustaining Ca pital		000C$	$0	$0	$6,636	$5,686	$4,895	$3,809	$2,064	$1,598	$0	$0
Closure			$0	$0								$38,723
Total Capital Costs		000C$	$17,571	$343,236	$6,636	$5,686	$4,895	$3,809	$2,064	$1,598	$0	$38,723
		C$/lbU3O8										
PRE-TAX CASH FLOW		000C$	($17,571)	($343,236)	$4,009	$1,757	$42,417	$125,400	$165,402	$113,408	$118,933	($38,723)
Annual												
Cumulative			($14,836)	($292,830)	($166,152)	($63,461)	$86,184	$266,026	$453,597	$588,704	$728,528	$698,528
INTERNAL RATE OF RETURN		%	8.1%									

Table 3 – Matoush Financials (2014)

The internal rate of return fell to 8.1% – far too low to secure financing. Not surprisingly, the Matoush project was immediately cancelled.

[68] Metal Prospects Uranium Market Outlook – Third Quarter 2014. RBC, 11-Jul-2013, page 1.

As discussed in our analysis of future U3O8 prices, RBC's forecast still appears too optimistic.[69] The problem is that global uranium demand has been falling, not increasing, a trend that seems likely to continue.

Using a forecast of US $40/lb through 2024, the internal rate of return becomes undefined – the project simply has no return.

YEAR			2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
PHYSICALS												
AM15 & MT34		%U3O8			169.8	240.6	132.7	130.4	118.8	23.5		
Gr ade		000t			0.64%	0.40%	0.44%	0.56%	0.64%	1.33%	0.00%	
MT22		%U3O8			-	-	130	131.8	130.8	200.6	239.6	
Gr ade					0.00%	0.00%	0.48%	0.48%	0.49%	0.40%	0.47%	
Tota l		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6	
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%	
Contained Meta l		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30	
Production Rate		tpd			485	688	750	749	713	640	685	
METALLURGY												
Mill Feed		000t			169.8	240.6	262.7	262.2	249.5	224.1	239.6	
Grade		%U3O8			0.64%	0.40%	0.46%	0.52%	0.56%	0.50%	0.47%	
Contained Meta l		000lbs			2,391.30	2,124.20	2,668.90	3,018.90	3,085.00	2,451.20	2,472.30	
Recovered Metal	97.60%	000lbs			2,333.90	2,073.20	2,604.90	2,946.50	3,010.90	2,392.40	2,413.00	
REVENUE												
Metal Price	40	US$/lb			$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	
Exchange Rate	0.85	US$/C$			0.9065	0.9093	0.9122	0.910298	0.910471	0.910645	0.910818	
Gross Revenue					$102,985	$91,200	$114,225	$129,474	$132,279	$105,086	$105,971	
Transport	0.1	per lb			$233	$207	$260	$295	$301	$239	$241	
Net Smelter Return (NSR)					$102,752	$90,993	$113,964	$129,179	$131,978	$104,847	$105,729	
Royalty	2.00%				$2,055	$1,820	$2,279	$2,584	$2,640	$2,097	$2,115	
NSR after Royalty					$100,697	$89,173	$111,685	$126,596	$129,338	$102,750	$103,615	
OPERATING COSTS												
Total		000C$			$90,052	$92,902	$92,359	$92,550	$91,506	$90,729	$88,533	
Unit Costs												
Mining		C$/tmilled			$121.75	$95.06	$85.49	$86.19	$87.34	$94.54	$81.34	
Process		C$/tmilled			$128.67	$90.77	$83.16	$83.29	$87.53	$97.45	$91.15	
Power		C$/tmilled			$49.63	$35.01	$32.08	$32.13	$33.76	$37.59	$35.16	
Maintenance		C$/tmilled			$34.49	$24.33	$22.29	$22.33	$23.46	$26.12	$24.43	
SiteServices		C$/tmilled			$45.33	$31.98	$29.30	$29.35	$30.84	$34.33	$32.12	
G&A		C$/tmilled			$31.12	$21.95	$20.11	$20.14	$21.17	$23.57	$22.04	
Total		C$/tmilled			$411.00	$299.09	$272.42	$273.42	$284.10	$313.60	$286.24	
		000C$			$38.58	$44.81	$35.46	$31.41	$30.39	$37.92	$36.69	
OPERATING PROFIT					$10,644	($3,730)	$19,326	$34,046	$37,832	$12,021	$15,082	
CAPITAL COSTS												
Total Capital Costs		000C$	$17,571	$343,236	$6,636	$5,686	$4,895	$3,809	$2,064	$1,598	$0	$38,723
		C$/lbU3O8										
PRE-TAX CASH FLOW		000C$	($17,571)	($343,236)	$4,009	($9,415)	$14,432	$30,237	$35,768	$10,423	$15,082	($38,723)
Annual												
Cumulative			($14,836)	($292,830)	($166,152)	($63,461)	$86,184	$266,026	$453,597	$588,704	$728,528	$698,528
INTERNAL RATE OF RETURN		%	None									
NET PRESENT VALUE (NPV)	5.00%	C$million	$475.55	($280.05)								
	8.00%	C$million	$377.64	($269.29)								
	10.00%	C$million	$323.53	($262.35)								
	15.00%	C$million	$218.07	($245.75)								

Table 4 – Matoush Financials (projected)

[69] U3O8 Forecast, Robert McCullough, 15-Aug-2014.

Appendix C: Nuclear Plant Life Expectancy

Nuclear power, and the technology that produces it is distinct among other methods of energy production. For example, in the U.S., there is a large difference between the relicensing of, say, hydroelectric facilities at the Federal Energy Regulatory Commission and the relicensing of nuclear facilities at the Nuclear Regulatory Commission.

Hydroelectric relicensing addresses a wide variety of prospective economic, environmental, and engineering issues. A successful relicensing carries with it a high probability of the operation of the plant through the life of the new license. A license from the Nuclear Regulatory Commission, on the other hand, represents permission to continue operating the plant, but carries no overall assurance of continued operation.

A recent *New York Times* article noted:

> When the Nuclear Regulatory Commission began routinely authorizing reactors to run 20 years beyond their initial 40-year licenses, people in the electricity business began thinking that 60 was the new 40. But after the last few weeks, 40 is looking old again, at least in reactor years, with implications for the power plants still running, and for several new ones being built.[70]

Recent examples of nuclear plant closures include the Gentilly-2 Station owned by Hydro-Quebec; Kewaunee Power Station in Wisconsin, owned and operated by Dominion; the San Onofre Nuclear Generating Station owned by Southern California Edison, San Diego Gas & Electric, and the City of Riverside; and Duke Energy's Crystal River 3 Nuclear Power Plant in Florida.

i) Gentilly-2 Nuclear Generating Station

Quebec's sole nuclear power plant stopped production in December of 2012, after 29 years of generating electricity. The license for the Gentilly-2 reactor, located near Bécancour, Que., about 150 kilometers northeast of Montreal, was set to expire that year and refurbishing it would have cost nearly $4.3 billion, plus another $2 billion to decommission the plant after the new license expired, according to Hydro-Québec. The estimated cost of letting the license expire without renewal on the other hand, was $1.8 billion at the time. Renewing its license would have meant the plant could have operated for another 30 years.

[70] Wald, Matthew L. *Nuclear Plants, Old and Uncompetitive, Are Closing Earlier Than Expected.* New York Times. 14 Jan. 2013. Web. 18 Sept. 2013. <http://www.nytimes.com/2013/06/15/business/energy-environment/aging-nuclear-plants-are-closing-but-for-economic-reasons.html>

For the next 18 months, a team of 485 employees worked to decommission the reactor. They discharged the reactor's fuel in September 2013, and went on to treat heavy water and deactivate most of the plant's systems. The fuel and contaminated water are to be kept in holding pools for seven years, then transferred to dry storage. Hydro-Quebec remains responsible for the site within a 15 km radius, and is answerable to CNSC. They are required to sample physicochemical and radiological conditions, and send reports to government authorities on a quarterly basis.

Gentilly-2 will now undergo a "sleeping" stage for 40 years, though the management and security of the area will hardly be passive. Hydro-Quebec remains responsible, and both they and the CNSC maintain an office and staff on-site. Around 2050, removal of the spent fuel will begin, as the plant is prepared for eventual dismantling. By 2062, the used fuel rods will have been completely removed from the location and the plant will be completely taken apart.

ii) Kewaunee Nuclear Plant

The Kewaunee Nuclear Plant is a 556 MW Pressurized Light Water Reactor (PWR) located in Carlton, Wisconsin. On May 7, 2013, the plant was permanently closed entirely for economic reasons.

The plant began operations in June 1974 and was originally owned by Wisconsin Public Service Corp (WPS) and Wisconsin Power and Light, a subsidiary of Alliant Energy. Dominion Energy purchased the plant for $192 million in 2005. As part of the deal, WPS and Alliant agreed to purchase power at a fixed rate from Kewaunee through 2013 when the plant's license expires. Kewaunee received a new license on December 21, 2011 allowing operation unit December 21, 2033.[71]

Dominion experienced operational, maintenance, and strategic difficulties at the Kewaunee plant. For a month in 2011, a link that provides radiation data to control room operators was broken at the Kewaunee plant.[72] Dominion was also fined $70,000 by the NRC for falsifying records and failing to conduct fire drills. Dominion planned to acquire more reactors in the Midwest to benefit from economies of scale since it is not as profitable to operate a stand-alone nuclear plant without other assets in the vicinity.[73] The plant struggled in the

[71] Nuclear Regulatory Commission. *Kewaunee Power Station*. NRC.gov. 2 Aug. 2013. Web. 18 Sept. 2013. <http://www.nrc.gov/info-finder/reactor/kewa.html>.
[72] Nuclear Regulatory Commission. http://www.nrc.gov/reading-rm/doc-collections/enforcement/actions/reactors/k.html
[73] Wald, Matthew L. New York Times. "Aging and Expensive, Reactors Face Mothballs." New York Times. 23 Oct. 2012. Web. 19 Sept. 2013 <http://www.nytimes.com/2012/10/24/business/energy-environment/economics-forcing-some-nuclear-plants-into-retirement.html?_r=1&>

face of low natural gas prices, high fixed costs, and expensive repairs which made it difficult to compete.

The company spent over a year trying to sell the plant, but no buyer emerged. Even though the license was renewed through 2033, the company announced that the plant did not improve shareholder value or support its objectives to provide a return on invested capital, so they decided to close its doors at its scheduled refueling in May of 2013.[74,75,76] Dominion spokesman Mike Kanz cited plummeting electricity prices on the wholesale regional power market and the inability to acquire more reactors in the Midwest to benefit from economies of scale. In addition, Kewaunee's power purchase agreements were ending at a time when Wisconsin utilities shunned high priced nuclear energy in favor of low priced natural gas.[77]

The Midwest Independent System Operator (MISO) determined that grid reliability would not be affected as a result of the Kewaunee nuclear plant closing. In a letter to Dominion, MISO wrote that "After being reviewed for power system reliability impacts, the retirement of Kewaunee would not result in violations of applicable reliability criteria. Therefore, Kewaunee may retire immediately." [78] Once the fuel has been removed from the reactor, the license will no longer authorize operating the plant. The license remains in effect until the company completes decommissioning and the NRC sends notification of license termination.

All of the spent fuel that has been used since 1974 is located on site, with only a very small amount moved to dry cask storage. Dominion will spend an estimated $340 million upfront for the disposal of spent fuel, which is presumably to be reimbursed by the federal government when it establishes a high-level waste repository.[79,80] Currently, eight dry casks storage

[74] Dominion. *Midwest ISO Concludes That Closing Of Kewaunee Power Station Will Not Affect Regional Electric Reliability. Dom.mediaroom.com*. 19 Feb. 2013. Web 3 Dec. 2013. <http://dom.mediaroom.com/2013-02-19-Midwest-ISO-Concludes-That-Closing-Of-Kewaunee-Power-Station-Will-Not-Affect-Regional-Electric-Reliability>.
[75] Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Jsonline.com. Milwaukee Wisconsin Journal Sentinel. <http://www.jsonline.com/business/kewaunee-nuclear-power-plant-shutdown-cost-is-nearly-1-billion-lr9j5fg-203912611.html>.
[76] Wald, Matthew, *Aging and Expensive, Reactors Face Mothballs.*
[77] Content, Thomas. *Community vents over timeline for nuclear plant decommissioning.* Jsonline.com. Milwaukee Wisconsin Journal Sentinel. 25 Apr. 2013. Web. 3 Dec. 2013. <http://www.jsonline.com/business/community-vents-over-timeline-for-nuclear-plant-decommissioning-q99n7mg-204769391.html>
[78] Dominion. *Midwest ISO Concludes That Closing Of Kewaunee Power Station Will Not Affect Regional Electric Reliability.*
[79] Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Milwaukee Wisconsin Journal Sentinel, 20 Apr. 2013
[80] Ibid.

modules are on site, with the potential to hold an additional 32 storage modules. The contents of the spent fuel pool will be transferred to dry cask storage by the end of 2019.[81,82]

Dominion selected the SAFSTOR decommissioning approach. Once the plant is shut down and defueled, the facility is stabilized and maintained in a safe storage state. At the end of the storage period, the facility is dismantled and decontaminated to a level that permits license termination. Fuel is removed from the reactor vessel and stored in the spent fuel pool for around seven years. At that point, the spent fuel will be transferred to the onsite Independent Spent Fuel Storage Installation (ISFSI) until the DOE locates a permanent repository.[83]

Detailed decommissioning costs for Kewanee are located on page 90 of the "Kewaunee Post Shutdown Decommissioning Activities Report".[84] The following chart provides a summary of the projected $920 million of decommissioning costs:

[81] Ryman, Richard. *Kewaunee nuclear plant VP talks about shutdown*. *Greenbaypressgazette.com*. Green Bay Press Gazette. 29 Apr, 2013. Web. 3 May 2013. <http://www.greenbaypressgazette.com/article/20130428/GPG03/304280308/Kewaunee-nuclear-plant-VP-talks-about-shutdown>.

[82] Content, Thomas. *Kewaunee nuclear power plant shutdown cost is nearly $1 billion.* Milwaukee Wisconsin Journal Sentinel, 20 Apr. 2013

[83] Dominion Energy. *Kewaunee Power Station, Post Shutdown Decommissioning Report.* 26 Feb. 2013. Web. 3 Dec. 2013. <http://pbadupws.nrc.gov/docs/ML1306/ML13063A248.pdf>.

[84] Ibid.

Kewaunee Power Station Schedule and Costs of Decommissioning (2012 dollars)				
Description	**Start**	**End**	**Years**	**Cost**
A. License Termination				
SAFSTOR Planning, Preparations, and Deactivation	7/1/2013	11/30/2014	1.41	$99,274,000
SAFSTOR Preparation, Delay During Wet Fuel Storage	11/30/2014	7/1/2020	5.58	$25,105,000
Completion of SAFSTOR Preparations	7/1/2020	12/28/2020	0.49	$15,899,000
Dormancy With Dry Storage	12/28/2020	10/19/2050	29.8	$51,910,000
Dormancy Only	10/19/2050	4/17/2067	16.49	$28,550,000
Decommissioning Planning During Dormancy	4/17/2067	6/22/2069	2.18	$42,755,000
Dismantlement Site Modifications and Preparations	6/22/2069	5/24/2070	0.91	$64,972,000
Systems Removal	5/24/2070	10/26/2071	1.42	$153,318,000
Site Decontamination	10/26/2071	8/29/2072	0.84	$61,058,000
			59.12	**$542,841,000**
B. Spent Fuel				
Spent Fuel Planning, Cooling and Transfer to Dry Storage	7/1/2013	7/1/2020	7	$175,227,000
Dry Storage During Completion SAFSTOR Preparations	7/1/2020	12/28/2020	0.49	$2,665,000
Dry Storage During Dormancy	12/28/2020	10/19/2050	29.8	$161,714,000
ISIFI Demolition	10/19/2050	7/31/2073	0.33	$2,622,000
			37.62	$342,228,000
B. Greenfield				
Clean Building Demolition	8/29/2072	7/31/2073	0.91	$30,827,000
Site Restoration	7/31/2073	12/4/2073	0.34	$3,976,000
			1.25	$34,803,000
SCENARIO TOTAL				**$919,872,000**

Table 5 – Decommissioning Costs at Kewaunee

Source: Kewaunee Power Station Post-Shutdown Decommissioning Activities Report[85]

iii) San Onofre Nuclear Generating Station (SONGS)

The San Onofre Nuclear Generating Station (SONGS) was a three unit pressurized water reactor located on the Pacific Plate of the active San Andreas Fault line in San Diego County.[86] Unit 1 was operational for 25 years before it was decommissioned in 1992. Units 2 and 3 became operational in 1983 and 1984 respectively. Southern California Edison (SCE)

85 Nuclear Regulatory Commission. "Kewaunee Power Station Post-Shutdown Decommissioning Activities Report." Nrc.gov, 26 Feb. 2013. Web. <http://pbadupws.nrc.gov/docs/ML1306/ML13063A248.pdf >

86 Gerhardt, Tina. *San Onofre Nuclear Generating Station to Remain Shuttered. Washingtonmonthly.com*. Washington Monthly. 23 Jul. 2012. Web. 3 Dec 2013. <http://www.washingtonmonthly.com/ten-miles-square/2012/07/san_onofre_nuclear_generating038760.php>

holds a 78% ownership stake, Sempra Energy's San Diego Gas & Electric holds 20%, and the City of Riverside has the remaining stake.[87]

SCE completed a $671 million steam generation replacement project in 2011 for Units 2 and 3. During a routine refueling outage in January 2012, SCE operators found a small leak in the steam generator tube in Unit 3 which allowed radioactive steam to mix with the steam going outside the containment building to the generators. [88] Both units were shut down for inspection and substantial degradation of the newly installed tubes was discovered.[89] By July 2012, the NRC said "the plant will not be permitted to restart until the licensee has developed a plan to prevent further steam generator tube degradation and the NRC independently verifies that it can be operated safely." [90]

The alternatives SCE examined included closing the plant and either buying replacement power on the market or building replacement generation. The conclusion reached was that a cross-over point was reached where operating Unit 2 no longer costs less than the alternatives.[91]

On June 7, 2013, SCE announced that units 2 and 3 of SONGS would be prematurely retired. Ted Craver, Southern California Edison's chairman and chief executive officer, said that instead of "continu[ing] to spend approximately $30 million a month to keep the plant ready for restart, and prolong the uncertainty surrounding the plant, we have decided to no longer seek to restart SONGS.[92]

Over the next year, the plant's workforce was cut from 1,500 to about 400 — a workforce charged with securing the plant during the potentially decades-long decommissioning process. Daniel Dominguez, Business Manager for Utility Workers Union of America Local 246, said the employees were disappointed but will now focus on keeping the facility safely

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[87] O'Grady, Eileen. *Grid looking at extended San Onofre nuclear outage.* Uk.reuters.com. Reuters. 21 Mar. 2012. Web. 3 Dec 2013. <http://uk.reuters.com/article/2012/03/21/utilities-california-sanonofre-idUKL1E8ELSYE20120321>.

[88] Spotts, Pete. *California nuclear plant to shut: a case of unforgiving nuclear economics.* Csmonitor.com. Christian Science Monitor. 7 Jun. 2013. Web. 3 Dec. 2013. <http://www.csmonitor.com/Environment/2013/0607/California-nuclear-plant-to-shut-a-case-of-unforgiving-nuclear-economics>

[89] O'Grady, Eileen. *Grid looking at extended San Onofre nuclear outage.*

[90] Gerhardt, Tina. *San Onofre Nuclear Generating Station to Remain Shuttered.*

[91] Craver, Ted. *Prepared Remarks of Ted Craver Chairman and Chief Executive Officer, Edison International EIX SONGS Update Conference Call.* Edison.com. Edison International. 7 Jun. 2013. Web. 3 Dec. 2013. <http://www.edison.com/files/EIX SONGS Update Call CEO Prepared Remarks 6-7-2013.pdf>

[92] Ibid.

shut down: "We're all professionals," he said. "It's unfortunate the plant was shut down, but it is what it is."[93]

iv) Crystal River 3

On February 5, 2013, Duke Energy announced plans to retire Crystal River Unit 3 in Florida. This was shortly after Duke had acquired Progress Energy, which owned Crystal River. Crystal River Unit 3 was licensed to operate through 2016, and an application to extend the operating life of the unit to 2036 was under review by the NRC. Crystal River Unit 3 was shut down in September 2009 to refuel and to replace its steam generators. During the shutdown, workers discovered damage to the concrete wall of the containment building, and additional damage occurred during subsequent repairs in 2011. Although a 2012 report indicated that the damage could be repaired and the plant restored to service, the uncertainty surrounding the cost and timing of repairs ultimately led Duke Energy to retire Crystal River Unit 3.[94]

The company and its insurance carrier, Nuclear Electric Insurance Limited (NEIL), have reached a resolution of the company's coverage claims through a mediation process. Under the terms of the mediator's proposal, NEIL will pay an additional $530 million. Along with the $305 million NEIL has already paid, customers will receive $835 million in insurance proceeds. This will be the largest claim payout in the history of NEIL.[95]

Duke filed its Post-Shutdown Decommissioning Activities Report (PSDAR) in December 2013. Their second quarter report indicates a write down of an additional $295 million over current decommissioning funds.[96]

v) Mark Cooper's Renaissance in Reverse: Aging Nuclear Reactors

In July of 2013, Dr. Mark Cooper of the Vermont Law School Institute for Energy and the Environment released a report on the economics of nuclear energy titled, "Renaissance in Reverse: Competition Pushes Aging U.S. Nuclear Reactors to the Brink of Economic Abandonment." His report shows that four recent early retirements of U.S. nuclear plants, alt-

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[93] Sewell, Abby and Anh Do. *San Onofre closure generates mixed feelings*. Latimes.com. Los Angeles Times. 23 Jun. 2013. Web. 3 Dec. 2013. <http://articles.latimes.com/2013/jun/23/local/la-me-adv-nuclear-neighbors-20130624-1>.

[94] Energy Information Administration. *Lower power prices and high repair costs drive nuclear retirements*. Eia.gov. 2 Jul. 2013. Web. 3 Dec. 2013. <http://www.eia.gov/todayinenergy/detail.cfm?id=11931>.

[95] Duke Energy. *Crystal River Nuclear Plant to be retired; company evaluating sites for potential new gas-fueled generation*, Duke-energy.com. 5 Feb. 2013. Web. 3 Dec 2013. <http://www.duke-energy.com/news/releases/2013020501.asp>

[96] Duke Energy. *Duke Energy posts second quarter 2013 results*. August 7, 2013. Page 3.

hough received with shock by the nuclear industry, are suggestive of a broad array of economic and operational problems for nuclear energy in the U.S.. Dr. Cooper predicts more early retirements and argues that "Economic reality has slammed the door on nuclear power." [97,98]

Dr. Cooper lists eleven risk factors that contribute to early retirement in nuclear reactors but states that the main purpose of the report is to alert policy makers to the economics of nuclear power and demonstrate that "Policy efforts to resist fundamental economic reality of nuclear power will be costly, ineffective and counterproductive." [99] The report concludes that nuclear economics have always been marginal, and that nuclear plants are not competitive at any stage of their lifecycle.

The following table, updated for the reactors CGS and Vermont Yankee, identifies a number of at risk nuclear units:

[97] Cooper, Mark. *Renaissance in Reverse: Competition Pushes Aging US Nuclear Reactors to the Brink of Economic Abandonment.* Institute for Energy and the Environment, Vermont Law School, July 18, 2013. Page iii - iv.
[98] Ibid., Page 39.
[99] Ibid., Page 40.

Reactor	Economic Factors							Operational Factors			Safety Issues	
	Cost	Small	Old	Stand Alone	Merchant	20yr w/o Ext	25yr w/ Ext.	Broken	Reliability	Long Term Outage	Multiple Safety Issues	Fukushima Retrofit
RETIRED, 2013												
Kewaunee	X	X	X	X	X						X	
Crystal River	X		O					X		O	X	
San Onofre					X	X		X		O	X	
Vt. Yankee	X	X	X		X		O					X
AT RISK												
CGS	X			X							X	X
Ft. Calhoun	X	X	X	X			O	X		O	X	
Oyster Creek	X	X	X	X	X		O			X		X
Ginna	X	X	X		X		O				X	
Point Beach	X	X	X		X		O					
Perry	X	X		X	X	X					X	
Susquehanna	X			X	X				X			X
Davis-Besse	X		O	X	X		O		X	X	X	
Nine Mile Point	X		X		X		O			X	X	X
Quad Cities	X			X	X		O					X
Dresden	X		X		X		O					X
Millstone	X		O	X	X		O				X	
Pilgrim	X	X	X		X	X	O			X	X	X
Clinton	X			X	X	X						
South Texas	X			X	X	X				X		
Commanche Peak	X			X	X	X						
Three Mile Island	X		X	X	X		O			X		
Palisades	X		X		X		O			X	X	
Fitzpatrick	X		O	X	X		O			X		X
Sequoyah	X				X	X				X		
Hope Creek	X			X	X							X
Seabrook	X				X	X			X			
Indian Point	X		X		X		O			X		
Duane Arnold	X		O		X		O				X	X

	Cost	Small	Old	Stand Alone	Merchant	20yr w/o Ext	25yr w/ Ext.	Broken	Reliability	Long Term Outage	Multiple Safety Issues	Fukushima Retrofit
Calvert Cliff	X		O		X		O			X	X	
Browns Ferry			X				O		X	X	X	
Monticello	X	X	X			X	O				X	
Prairie Island	X	X	X				O				X	
Turkey Point	X	X	X			X	O			X	X	
Robinson	X		X			X						
Wolf Creek	X			X					X		X	
Fermi	X		X	X		X				X		
Diablo Canyon	X			X		X					X	
Cooper	X		X	X			O				X	
Callaway	X			X		X					X	
Cook	X		O				O		X		X	
LaSalle	X				X	X						X
Limerick	X				X	X						X

Table 6 – At-Risk Nuclear Facilities

Long term outage: X = past, O = current

Old: X = 1974 or earlier commissioning, O = commissioned 1975-1979 [100]

Cost/Age

Advocates of nuclear energy argue that new plants can be built at relatively low cost and that reactors will operate at high capacity for extended periods of time with low marginal costs. Recent early retirement decisions call into question these assumptions. The fleet is aging, and non-fuel O&M costs of nuclear plants are rising as a result.[101] Statistically, load factor for older plants is 4% lower than in newer plants, representing an important loss of revenue in tight economic times.[102] As margins shrink they become less able to cover the weighty fixed costs of nuclear units, and as reactors age, they become farther out of touch with modern safety standards, requiring costly retrofits. [103]

A 2013 UBS analysis described the economic difficulties for aging reactors:

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[100] Cooper, *Renaissance in Reverse,* Pages 24-5.
[101] Ibid., Page 5.
[102] Cooper, *Renaissance in Reverse,* Page 14.
[103] Ibid., Page 5.

> Despite substantially lower fuel costs than coal plants, fixed costs are approximately 4-5 times higher than coal plants of comparable size and may be higher for single-unit plants. … We believe 2013 will be another challenging year for merchant nuclear operators, as NRC requirements for Fukushima-related investments become clearer in the face of substantially reduced gas prices. While the true variable cost of dispatching a nuclear plant remains exceptionally low (and as such will continue to dispatch at most hours of the day no matter what the gas price), the underlying issue is that margins garnered during dispatch are no longer able to sustain the exceptionally high fixed cost structures of operating these units.[104] [105]

Small/Stand-alone

Small stand-alone units isolated geographically and organizationally are more vulnerable to economic pressures because they are less able to benefit from economies of scale or spread costs out over larger capacity and output. While some plants choose to outsource management to a more experienced party, this does not necessarily mean a decrease in costs for the nuclear plant. The management service provider may in fact capture the financial benefits of scale integration and experience rather than the owner.[106]

Merchant

Merchant plants are thought to face more immediate risk than regulated reactors because economic pressures directly affect their competitiveness. Decreasing prices in electricity markets are a powerful indicator to policy makers responsible for decisions about retiring regulated plants.

Cooper explains that regulators are supposed to emulate the market in decision-making,

> Those who fail to do so are allowing the utilities to act imprudently, in violation of public utility law. The fact that markets across the country are yielding similar economic results is strong evidence about the true economics of nuclear power in today's electricity market in the U.S. today. This should influence regulatory decisions.[107]

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104 Ibid., Page 6.

105 Dumoulin-Smith, Julien, and Jim Von Riesemann. *In Search of Washington's Latest Realities (DC Fieldtrip Takeaways).* UBS Investment Research (2013): Nrc.gov. 20 Feb. 2013. Web. 21 Oct. 2013. <http://pbadupws.nrc.gov/docs/ML1312/ML13128A302.pdf>.

106 Cooper, *Renaissance in Reverse,* Page 17.

107 Ibid., Page 11.

He finds that three dozen reactors in the U.S. that have significant economic issues could easily be retired early, and that although the market will operate faster for merchant reactors, economic pressures are so intense that regulators are being forced to take action as well.

License Extension

Although a short license is on the list of risk factors for early retirement, a long license is not a guarantee of long life. The Kewaunee plant had just had its license extended for 20 years, but closed for purely economic reasons. The same proved to be true for Vermont Yankee, which had also had its license extended.[108]

Broken/Reliability/Long Term Outage

The U.S. Energy Information Administration has recently noted that in the current market, aging reactors in need of significant repair may not warrant the investment. Mechanical and safety related problems are among the factors considered likely to push an at-risk reactor over the line into early retirement.

As reactors age, they are more likely to experience outages. Outages can be caused by needed repairs, retrofits, or recovery of broken components, and the average cost of an outage in 2005 dollars was more than $1.5 billion. When reactors are offline, the owners must replace the power. This causes problems when demand for power increases, pushing up the market clearing price. Moody's reports that currently the low price of natural gas is masking the seriousness of this problem. Cooper reports on a study by David Lochbaum which finds that, since the start of the commercial industry, more than one quarter of all U.S. reactors have had an outage of one year or more.[109,110]

Safety/Fukushima Retrofit

Safety retrofits are another factor that can easily push at-risk reactors over the edge. Fukushima retrofits specifically will be a significant expense for many plants.

A 2013 UBS report said,

> Among our greatest concerns for the U.S. nuclear portfolio into 2013 is the risk of greater Fukushima-related costs. While expectations around the need of hardened

[108] Nuclear Regulatory Commission. *Vermont Yankee Nuclear Power Station - License Renewal Application*. Nrc.gov, Web. 21 Oct. 2013. <http://www.nrc.gov/reactors/operating/licensing/renewal/applications/vermont-yankee.html>.
[109] Lochbaum, David. *Walking a Nuclear Tightrope Unlearned Lessons of Year-plus Reactor Outages*. Cambridge: UCS Publications, 2006. Ucsusa.org. Web. 21 Oct. 2013. <http://www.ucsusa.org/assets/documents/nuclear_power/nuclear_tightrope_report-highres.pdf>. Page 17.
[110] Cooper, *Renaissance in Reverse*, Page 28.

> vents differ, we see cost risks of up to $30-40 Mn/per unit under a worst case scenario; while other estimates suggest costs range in the $15 Mn ballpark. Notably, PPL ests. [in Pennsylvania] Fukushima-related costs of $50-60 Mn, excluding vents for its 1.6 GW Susquehanna unit.[111]

Renewables/Low Natural Gas Prices

While nuclear construction costs and cost-estimates are rising, market prices are falling and renewable alternatives are becoming cheaper thanks to technological innovation, economies of scale, and learning by doing. Whether or not the U.S. adopts carbon emission policies, there are numerous energy sources available to meet electricity demand at a lower cost than nuclear, and other low-carbon energy sources would stand to benefit as much or more than nuclear energy under climate policy. Solar prices are expected to continue decreasing and investment in energy efficiency is expected to increase, decreasing demand growth.

Most reasonable analysts have reached consensus that the price of natural gas can be expected to remain low for a significant time. This among other lower-cost sources of energy are adding pressure to the already shaky economics of nuclear power.[112]

Demand

"Energy efficiency," Cooper points out, "is the cheapest, cleanest and fastest energy source available today – it is significantly less expensive than nuclear and involves no safety issues, waste disposal problems and lengthy construction delays." [113] In the time frame relevant for retirement decisions, nuclear is unlikely to become competitive with low carbon alternatives and natural gas prices are likely to remain low.[114]

vi) Statistical Analysis of Plant Life Expectancy

There is an optimistic impression in some quarters that the granting of an additional NRC license assures that a plant will operate for another thirty years. Of the five units currently commencing decommissioning, Kewaunee and Vermont Yankee were recently relicensed. The San Onofre and Crystal River 3 units had commenced, but not completed, relicensing as of their closure.

[111] Dumoulin-Smith, Julien. *In Search of Washington's Latest Realities,* Page 1.
[112] Cooper, *Renaissance in Reverse,* Pages 33-5.
[113] Cooper, Mark. *Why Nuclear Reactor Loan Guarantees Are Now More Imprudent Than Ever.* Yubanet.com, 14 Feb. 2011. Web. 21 Oct. 2013. <http://yubanet.com/opinions/Mark-Cooper-Why-Nuclear-Reactor-Loan-Guarantees-Are-Now-More-Imprudent-Than-Ever.php>.
[114] Cooper. *Renaissance in Reverse.* Page iii.

There are three readily available data sets for analysis of expected nuclear plant life expectancy:

1. World wide data from the IEA;
2. U.S./Canadian data from the NRC and the Canadian Nuclear Safety Commission; and,
3. West Coast data from the NRC.

Even a cursory review indicates that the conclusions drawn from the U.S./Canadian and world data sets give very different results than West Coast data.

The following chart shows the relationship between average plant life and the percentage of decommissioned units:

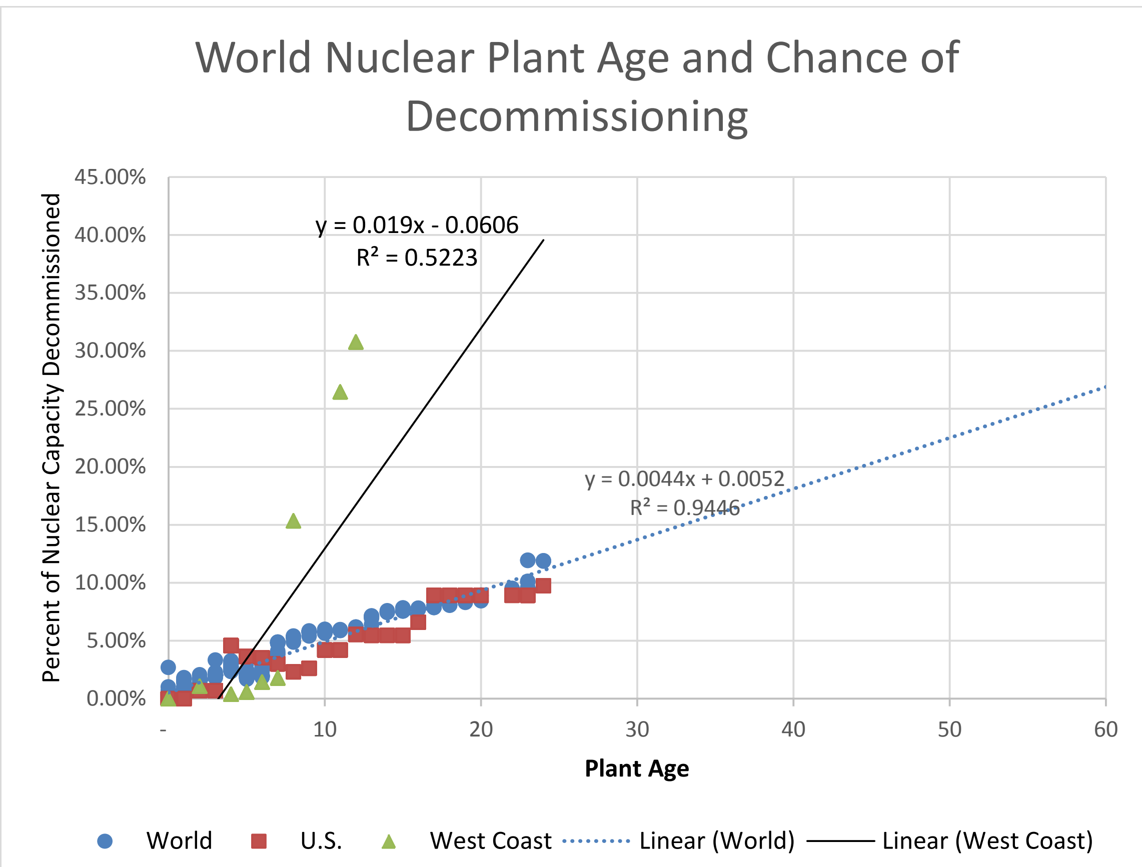

Figure 16 – Plant Age and Chance of Decommissioning

This analysis indicates that for plants outside of the West Coast of the U.S. the chance of closure is .4% per year. The West Coast analysis is very different – almost 2% per annum.

Human life expectancy analyses often start with a simple tool like the following "life table."[115]

Table VI. Life table for the total population: United States, 2008

Age (years)	Probability of dying between ages x and $x+n$ $_nq_x$	Number surviving to age x l_x	Number dying between ages x and $x+n$ $_nd_x$	Person-years lived between ages x and $x+n$ $_nL_x$	Total number of person-years lived above age x T_x	Expectation of life at age x e_x
0–1	0.006593	100,000	659	99,425	7,812,389	78.1
1–4	0.001132	99,341	112	397,092	7,712,964	77.6
5–9	0.000623	99,228	62	495,972	7,315,872	73.7
10–14	0.000779	99,167	77	495,692	6,819,900	68.8
15–19	0.002875	99,089	285	494,821	6,324,208	63.8
20–24	0.004689	98,804	463	492,902	5,829,387	59.0
25–29	0.004861	98,341	478	490,514	5,336,485	54.3
30–34	0.005466	97,863	535	488,017	4,845,971	49.5
35–39	0.007077	97,328	689	485,012	4,357,954	44.8
40–44	0.010733	96,639	1,037	480,795	3,872,942	40.1
45–49	0.016773	95,602	1,604	474,262	3,392,147	35.5
50–54	0.025150	93,999	2,364	464,410	2,917,885	31.0
55–59	0.035784	91,635	3,279	450,415	2,453,475	26.8
60–64	0.052463	88,356	4,635	430,823	2,003,060	22.7
65–69	0.078443	83,720	6,567	403,086	1,572,237	18.8
70–74	0.118559	77,153	9,147	364,140	1,169,152	15.2
75–79	0.182982	68,006	12,444	310,338	805,011	11.8
80–84	0.283728	55,562	15,764	239,561	494,673	8.9
85–89	0.438470	39,797	17,450	155,294	255,112	6.4
90–94	0.628469	22,347	14,045	74,038	99,818	4.5
95–99	0.797603	8,303	6,622	22,048	25,780	3.1
100 and over	1.000000	1,680	1,680	3,732	3,732	2.2

SOURCE: CDC/NCHS, National Vital Statistics System.

Table 7 – Life Table for U.S. Population

The primary input to a human life table is the probability of dying in a given year or set of years. In this case, for example, the chance of death in the early sixties is 5.2%. The primary output is the life expectancy in the leftmost column. The corresponding value for early 60s is 22.7 years.

No such simple solution exists for nuclear plants. From the discussion above, it is clear that there is substantial evidence that nuclear plants do not have an infinite lifetime. There is no readily established methodology to estimate what the expected life expectancy of a nuclear plant will be.

The same life table model can be applied to nuclear plants since we have data on the probability of closure at different plant ages.

[115] Arias, Elizabeth. *United States Life Tables, 2008*. Rep. no. 3. Vol. 61. National Vital Statistics System, 2012. Cdc.gov. Web. 21 Oct. 2013. <http://www.cdc.gov/nchs/data/nvsr/nvsr61/nvsr61_03.pdf>. Page 63.

Of the fifteen commercial nuclear reactors built on the West Coast, only six are now in operation – Diablo Canyon 1 and 2, Palo Verde 1, 2, and 3 and CGS.

A standard life table analysis of West Coast nuclear plants is reproduced below:

Age (years)	Probability of plant closure between ages x and x + n	Number surviving to age x	Number plant closure between ages x and x + n	Plant-years lived between ages x and x + n	Total number of Plant-years lived above age x	Expectation of life at age x
x	n qx	lx	n dx	n Lx	Tx	ex
1-5	0.0%	15.0	0.0	15.0	485.6	32.4
6-10	13.3%	15.0	2.0	29.0	410.6	27.4
11-15	15.4%	13.0	2.0	41.0	340.6	26.2
16-20	9.1%	11.0	1.0	51.5	280.6	25.5
21-25	10.0%	10.0	1.0	61.0	228.1	22.8
26-30	11.1%	9.0	1.0	69.5	180.6	20.1
31-35	25.0%	8.0	2.0	76.5	138.1	17.3
36-40	12.0%	6.0	0.7	82.1	103.1	17.2
41-45	12.0%	5.3	0.6	87.1	74.9	14.2
46-50	12.0%	4.6	0.6	91.5	50.1	10.8
51-55	12.0%	4.1	0.5	95.3	28.2	6.9
56-60	12.0%	3.6	3.6	98.7	9.0	2.5

Table 8 – Life Table for Nuclear Plants

The closure of San Onofre 2 and 3 this year gives a closure rate of 25% for the 31-35 age cohort. This raises a serious analytical problem. Is the high risk of plant closure on the West Coast going to continue or will the rate of closure fall back to the historical average of 12.0% for a future five year period? This assumes that risk of closure for the next five years – and following periods – are approximately half of current levels. While possible, this seems unlikely given current political and economic trends.

The table above assumes that recent closures were unusual. The alternative assumption, at least equally likely, is that plant closures are more likely with increasing age.

If so, a reasonable assumption is that the chance of plant closure will continue at current levels until the end of the analysis. Assuming that plant mortality risk for the next five years (and following years) is more intuitive since we would expect risk to increase over time:

	Probability of plant closure between ages x and x + n	Number surviving to age x	Number plant closure between ages x and x + n	Plant-years lived between ages x and x + n	Total number of Plant-years lived above age x	Expectation of life at age x
	n qx	lx	n dx	n Lx	Tx	ex
1-5	0.0%	13.0	0.0	13.0	397.8	30.6
6-10	13.3%	13.0	1.7	25.1	332.8	25.6
11-15	15.4%	11.3	1.7	35.5	272.2	24.2
16-20	9.1%	9.5	0.9	44.6	220.2	23.1
21-25	10.0%	8.7	0.9	52.9	174.7	20.2
26-30	11.1%	7.8	0.9	60.2	133.5	17.1
31-35	25.0%	6.9	1.7	66.3	96.7	13.9
36-40	25.0%	5.2	1.3	70.9	66.3	12.8
41-45	25.0%	3.9	1.0	74.3	43.6	11.2
46-50	25.0%	2.9	0.7	76.8	26.5	9.1
51-55	25.0%	2.2	0.5	78.7	13.7	6.3
56-60	25.0%	1.6	1.6	80.2	4.1	2.5

Table 9 – Life Table for Nuclear Plants (revised)