Susitna-Watana Cost of Power Analysis

June, 2013

Steve Colt
Institute of Social and Economic Research (ISER)
University of Alaska Anchorage
sgcolt@uaa.alaska.edu

The author acknowledges helpful comments from Mark Foster, Tobias Schwoerer, Matt Berman, and several anonymous peer reviewers. All errors and omissions are the author's.

Susitna-Watana Cost of Power Analysis

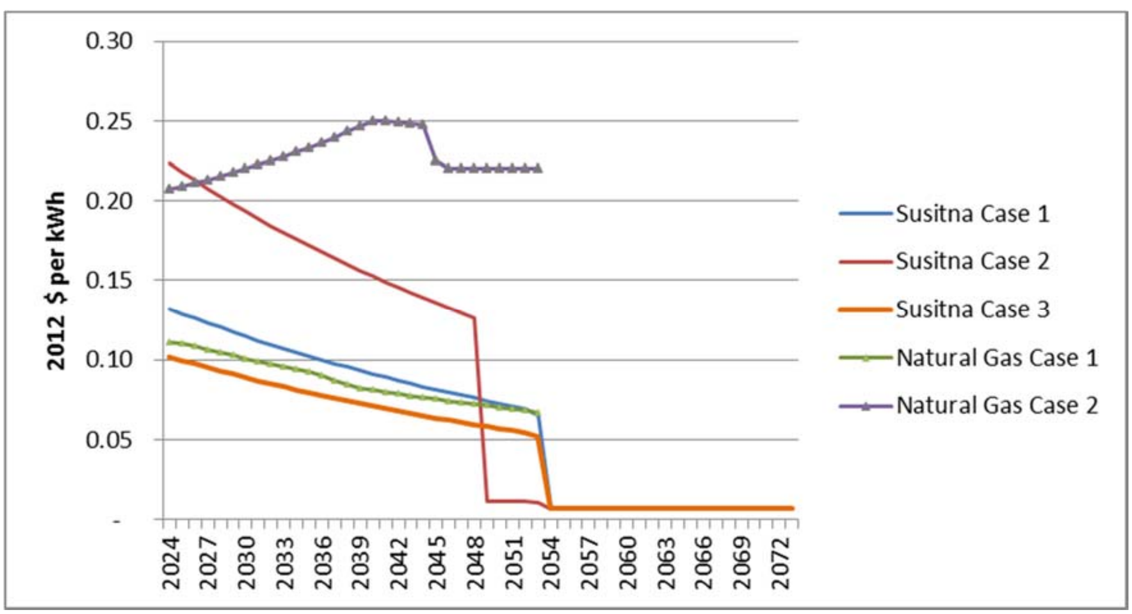
Contents

Summary

This paper provides a simple analysis of the cost of the proposed Susitna-Watana hydroelectric project from a ratepayer perspective, using data current as of June 2013. The Susitna Case 1 assumptions include a capital cost of 5.19 billion 2012 dollars, 100% debt financing at 5.0%, and an on-line date of 2024. Under these assumptions plus others described below, the production cost of Susitna power in 2024 would be 13 cents per kilowatt-hour (kWh) and the cost at a Railbelt customer's meter would be about 18 cents per kWh.[1] By comparison, if natural gas is available to electric utilities in year 2024 at a price of about $9.50 per million btu, and ignoring potential carbon taxes, then the production cost and retail cost of power from a new combined cycle gas turbine going online in 2024 would be about 11 cents and 16 cents per kWh, respectively.

Sensitivity analysis shows that the production cost of Susitna power could be substantially higher – about 21 cents per kWh in 2024 – if capital costs are 6% higher than the Case 1 estimates and the interest rate is 6.0%. That cost could also be lower – about 10 cents per kWh – if capital costs are 14% lower and the interest rate is 4%. And natural gas prices could also be much higher: Railbelt utilities might have to import LNG at prices higher than $20 per million btu (equivalent to 15 cents per kWh generated). The resulting production cost of gas-fired power would be 21 cents per kWh or more. After 2053 Susitna debt would be retired and the cost of power from hydro would drop significantly during an additional 50 years of hydro project service life.

Figure S-1. Production cost comparison



[1] All dollar amounts are inflation-adjusted 2012 dollars unless otherwise stated.

Introduction

The proposed Susitna-Watana dam is a capital-intensive 600 megawatt hydropower project with a 10-12 year lead time.[2] One potentially useful way to measure and express the cost of this and other power projects is from a utility ratepayer perspective. This paper presents a simple model of the cost of electricity and how that cost would be reflected in consumer rates. The model[3] is used to explore how different assumptions might affect the cost of Susitna power to Railbelt[4] ratepayers. To provide context for these costs, the model is also used to consider what the cost of power from natural gas might be during the same time period.

The results reported here are based on specific sets of assumptions that are clearly described below. However, if the actual inputs are different, then the ultimate costs will be different as well. Because of the high uncertainty inherent at this early stage of the project in some of the largest cost drivers, such as initial capital expense, different values for production cost and for retail rates are calculated based on different assumptions and inputs.

The primary motivation for this analysis is that the State of Alaska is directly involved in the Susitna project and is currently spending millions of dollars on studies in support of FERC licensing. The decisions to proceed with further studies, licensing, financing, or construction of this multi-billion dollar project are public policy decisions. Money spent directly on Susitna is unavailable for other energy projects and other state needs. It is therefore useful to have a reasonably clear understanding of the potential cost of this project from the perspective of those who would bear that cost – the people of Alaska – and to be able to compare that cost with the cost of other energy projects seeking public and private financing.

A second purpose of the paper is to present the model of ratemaking in enough detail to clearly demonstrate how both the up-front capital cost of a project such as Susitna and the onggoing fuel costs of a gas-fired plant are translated into consumer rates. This methodology can be used for similar comparisons with other proposed projects not considered here.

---

[2] An accessible background document describing the project is the AEA 2012 Report to the Legislature on Susitna Hydro. http://www.susitna-watanahydro.org/annualreport12/annual-report-2012.pdf
[3] The model is available for downloading at http://iser.alaska.edu. Search publications under "Susitna-Watana."
[4] The region of Alaska extending from the Kenai Peninsula north to Fairbanks is known within the state as the "Railbelt" and is served by a single electricity grid

The paper also develops a plausible range of potential future costs of electricity from natural gas. The purpose of presenting these potential costs is simply to provide some context for the Susitna cost numbers. The paper is not intended to provide a head-to-head comparison of Susitna hydro with gas-fired generation. Indeed, such an isolated head-to—head comparison would most likely not be appropriate or useful when considering power options to serve the interconnected Railbelt grid for the next 50 to 100 years.

Ratemaking methods

All of the Alaska Railbelt electric utilities are either cooperatives or municipally owned. Their rates are regulated by the Regulatory Commission of Alaska based on the cost of service.[5] Notably, the cost of building a new power plant or hydro project cannot be recovered until the project enters service. Expenditures prior to that time, including interest payments on borrowed funds used during construction, must be capitalized and recovered during the useful life of the investment.

The cost of service includes the major components shown in Table 1.

Table 1. Components of the cost of electric service for Alaska Railbelt utilities

		Component
1		Fuel and purchased power expense
2	+	Nonfuel operation and maintenance expense
3	+	Depreciation of power production plant
4	+	Interest on debt used to finance power production plant
5	=	**Power production cost of service**
6	+	Transmission cost (operating and capital)
7	+	Distribution cost (operating and capital)
8	+	Admin & General cost (operating and capital)
9	=	**Total cost of service**
10	+	Authorized margins
11	=	**Authorized total revenue requirement**

The funds known as “margins” (line 10 in Table 1) provide a financial cushion that is generally required by bondholders and/or granted by regulators. A primary purpose of margins is to ensure that authorized revenues are more than sufficient to pay interest on

[5] See, eg: Chugach Electric Association. 2012. TA-347-8. Semi-annual simplified rate filing. Especially Schedule 1 at page 46 of 214.
http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=253d3650-b7c6-4e59-98c0-8fca94ea835d

the utility's long-term debt. Alaska utilities typically are authorized to collect margins equal to about 30% of their own interest expense. [6,7]

According to the Alaska Energy Authority (AEA), rates for power from the Susitna project would not be made in the same way as the "standard method" described above. Instead, the actual amounts paid by AEA for debt service (interest and principal) on the Susitna project would be passed directly through to purchasers of wholesale power from the project with no additional amounts collected as margins.[8] The State of Alaska would stand behind the bonds used to finance the project, and a capital reserve fund equal to one year's debt service would be established and maintained until debt was retired.[9]

The AEA's proposed method for determining Susitna power rates substitutes the actual cash flows needed to pay debt service (interest plus principal) for the combination of depreciation plus interest used by the Railbelt utilities. It also substitutes specific financial measures -- such as the capital reserve fund, or a collection of additional revenue known as "debt service coverage" -- for the collection of margins. This "debt service method" of determining the cost of service is summarized in Table 2.

[6] See, eg, Chugach Electric TA 347-8. Table 1 at page 49. Margins of 30% times interest expense are sufficient to achieve a "Time Interest Earned Ratio", or TIER, equal to 1.3. TIER = (Net Margins + Interest on Long-Term Debt) / (Interest on Long-term Debt)

[7] RCA Staff Memorandum (Tariff Action Meeting Memorandum dated May 3, 2012.) Subject: TA347-8 Chugach Electric Association, Inc.'s SRF Tariff Filing for the Test Year Ended December 31,2011. "Chugach operates on a split Times Interest Earned Ratio (TIER) platform whereby the Commission has established a system-wide TIER of 1.30, based on a 1.10 TIER for wholesale customers, and a floating TIER for retail custorners." (p. 4).

[8] Alaska Energy Authority. 2012. Alaska Energy Authority Confident Susitna-Watana Hydro will provide Long-Term, Stable and Affordable Energy. This document states: "AEA is required by Alaska Statute (Sec 44.83.090) to sell power at the lowest reasonable prices. The State of Alaska would finance construction costs and make payments throughout the financing life." http://www.susitna-watanahydro.org/alaska-energy-authority-confident-susitna-watana-hydro-will-provide-long-term-stable-and-affordable-energy/

[9] "AEA's rate modeling assumes the financing will include one year of capital reserve to ensure sufficient cash flow to make debt payments." Alaska Energy Authority. "Susitna-Watana Hydro Cost of Power: Alaska Energy Authority Compares Estimates to Dr. Colt's Report" Press release, September 4, 2012.

Table 2. Components of the cost of electric service under the AEA proposed debt service method

		Component
1		Fuel and purchased power expense
2	+	Nonfuel operation and maintenance expense
3	+	Repayment of debt principal
4	+	Interest on debt used to finance power production plant
5	=	**Power production cost of service**
6	+	Transmission cost (operating and capital)
7	+	Distribution cost (operating and capital)
8	+	Admin & General cost (operating and capital)
9	=	**Total cost of service**
10	+	Possible additional "interest coverage" required by bondholders
11	=	**Authorized total revenue requirement**

The debt service method would probably result in lower Susitna wholesale power rates than the standard method during the early years of operation.[10] However, the difference in rates reverses during later years, for two reasons. First, repayments of debt principal become greater than annual depreciation. Second, any margins collected under the standard method would accumulate as retained earnings and could eventually be used to defray debt service and/or retire the debt early, leading to lower rates. The details depend on the circumstances, but the general point is that using the debt service method of making rates does not lead to permanently lower rates. Rather, the method shifts the timing of the cost burden to later years.

Susitna cost of power

In this section I document the assumptions and present the resulting cost of Susitna power for three Susitna cases, each based on different assumptions.

Susitna Case 1 assumptions

For what I will label Susitna Case 1, I have adopted without further adjustment the following set of assumptions provided by the AEA.[11]

[10] This conclusion is not always true. Early year rates could be higher under the debt service method if the depreciation lifetime is much longer than the bond repayment period. If the Susitna project were depreciated over 100 years but debt was repaid over 30 years, then debt principal repayments might exceed depreciation fairly early, leading to higher early year rates using the debt service method.

[11] Alaska Energy Authority. 2013. Susitna-Watana Hydro Economics. Presentation to House Resources Committee. February 15.

Project size: 735 foot dam height (= "Low Watana" project)

Installed generation capacity: 600 megawatts (MW)

Annual energy output: 2,800,000 megawatt-hours (MWh) per year

Construction cost: $5.190 billion year 2012 dollars. The construction cost includes a 20% contingency, road construction, and the cost of permitting and FERC licensing. It excludes land acquisition and any possible costs of mitigating fisheries impacts.

Transmission: Construction cost estimate includes transmission sufficient to reach the Railbelt grid. No further transmission upgrades are assumed to be attributable to the Susitna Project.

Interest rates: 2.0% during construction ("short-term")
5.0% long term debt upon project completion ("long-term")

Inflation rate: 2.50%. This rate, while provided by AEA, is also the rate used by Alaska Office of Management and Budget for fiscal year 2014 planning.[12]

Capital reserve: A capital reserve fund equal to one year of scheduled debt service is financed with bond proceeds and maintained until debt is retired. No additional revenue is required to be collected as debt service coverage.

Timeline: Licensing period: 2012-2016
Construction period: 2017-2023
Operation begins: 2024

Operation and maintenance costs: $16 million 2012 dollars per year

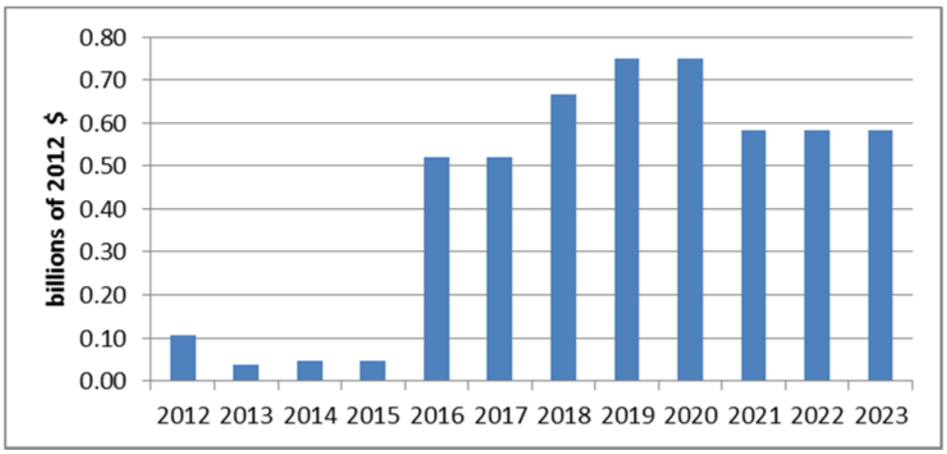
[12] Alaska OMB, 2012. Memorandum from Karen Rehfeld titled "2013 Legislative Session Fiscal Notes." November 5, 2012.

In addition to the above assumptions provided by AEA, I have assumed the following:

Outlay pattern. The 2009 economic analysis by HDR Engineering lists an outlay pattern spanning 14 years. AEA's current timeline spans 12 years from 2012 through 2023. I adjusted the HDR pattern to collapse their years 1,2,3 into 2012 while retaining the remaining pattern for 2013 through 2023. According to AEA's projections, 2024 is both the online year and final outlay year. To retain the transparency of the calculations, I have assumed that 2023 is the final year of capital outlay and that the project then produces a full year's output in 2024.

The resulting outlay pattern is shown in Figure 1.

Figure 1. Assumed outlay pattern



Capital replacements. I have included in the model an estimated $2 million per year (2012$) allowance for capital replacement costs. HDR (March 2009, p. 13) estimated capital replacements with a total cost of $22 million every 20 years plus an additional $43.6 million every 40 years, for a total of $87.6 million (2012 $) during the first 50 years. I determined through side calculations that annual nominal dollar payments of approximately $2 million (2012$) commencing in 2024 would be sufficient to fund these capital replacements using a sinking fund approach. In the model the $2 million per year for capital replacements are added to the $16 million to yield $18 million per year of combined annual expense.

Transmission, distribution, and other costs. I assume a 95% "delivery factor," meaning that 95% of all kWh generated by the Susitna project are delivered to a Railbelt customer's meter. This parameter is based on my analysis of net generation vs. sales for the Railbelt utilities in 2011.[13] I have assumed the cost per kWh for transmission, distribution, admin, general, and customer expense to be 4.8 cents per kWh in 2012 dollars. This estimate is based on data from the Chugach Electric Association 2012 Annual Report (p. 8) showing the difference between the average revenue collected per wholesale kWh and per retail kWh.

The above assumptions forming Susitna Case 1 are summarized in Table 3.

Table 3. Summary of Susitna Case 1 assumptions

Item	units	value
Installed capacity	MW	600
Energy output delivered to Railbelt grid	MWh	2,800,000
Service lifetime	years	100
Total capital cost - overnight basis	2012$ billion	5.190
Debt-financed fraction		100%
Grant-financed fraction		0%
Long-term debt interest rate	nominal %	5.0%
Long term debt repayment period	years	30
Short-term debt rate (during construction)	nominal %	2.0%
Financed reserve fund - ratio to debt service	ratio	1.00
Interest rate earned on short-run lending of FRF	nominal %	2.0%
Required debt service coverage ratio	ratio	1.00
General inflation rate	% per yr	2.50%
Annual O&M incl. capital replacements	2012$ billion	0.018
Ratio of retail kWh sold to kWh delivered to Railbelt grid		0.95
Transmission, distribution, & admin cost	2012$/kWh	0.048

Sample calculation

The methodology can be illustrated by stepping through the calculation of the revenue requirement per kWh for year 2024, the first year of operation and revenue collection. The steps are shown in the following table and then explained line by line.

[13] The raw data are reported in Alaska Energy Statistics 1960-2011. Data Tables. Accessed May 2013 at http://www.akenergyauthority.org/publications.html.

Table 4. Calculation of Susitna Case 1 year 2024 revenue requirement

line		item	units	2024 amount
1	**Operating expenses**			
2		Annual O&M incl. capital replacements	2012$ billion	0.018
3		**Subtotal operating**	2012$ billion	**0.018**
4				
5	**Debt service**			
6		Debt service payment on electric plant debt	$nominal billion	0.435
7		Interest payment (net) on financed reserve fund	$nominal billion	0.013
8		Total debt service nominal dollars	$nominal billion	0.448
9		**Subtotal debt service**	2012$ billion	**0.333**
10				
11	**Total production cost of power**		2012$ billion	**0.351**
12				
13	**Revenue requirements**			
14		Recovery of direct production cost	2012$ billion	0.351
15		Additional recovery to meet DS coverage reqts	2012$ billion	-
16		Application of retained earnings	2012$ billion	-
17	**Total revenue requirement for production cost**		2012$ billion	**0.351**
18		MWh delivered from powerhouse	MWh	2,800,000
19		MWH retail sales at customer meters	MWh	2,660,000
20	**Production revenue reqt per kWh sold**		2012$/kWh	**0.13**
21		Transmission, distribution, admin cost	2012$/kWh	0.05
22	**Total rev reqt = cost of power to retail customer**		2012$/kWh	**0.18**

The calculations are explained further as follows.

Line 2. Annual O&M = $18 million in 2012 dollars. This number includes an allowance for capital replacements.

Line 6. The construction cost to be financed at the beginning of 2024 equals 6.687 billion nominal dollars. This is the result of the construction outlay pattern during the years 2012-2023 with 1) each annual outlay escalated by the appropriate number of years of general inflation and 2) interest of 2% applied to and added on to the accumulating amount at the end of each construction year. Annual debt service on this amount at 5% for 30 years = $0.435 billion.

Line 7. The required capital reserve fund of $0.435 billion must initially be borrowed and then maintained. I assume that the borrower could earn short-term interest of 2.0% on this amount while paying 5% interest to bondholders. [0.435 * (.05 - .02) = 0.013]

Line 14. The sum of O&M plus debt service.

Line 18. Electric energy sold to final consumers = 95% of energy delivered to grid.
[2,800,000 * 0.95 = 2,660,000]

Line 20. Production revenue requirement per kWh sold = line 17 divided by line 19
[$351 million / 2,660,000 MWh = 0.13 dollars per kWh]

Line 21. Transmission, distribution, admin revenue requirement = $.048 (displayed as .05) in 2012 dollars.

Line 22. Total cost of power to consumer = 0.13 + 0.05 = $0.18 per kWh.

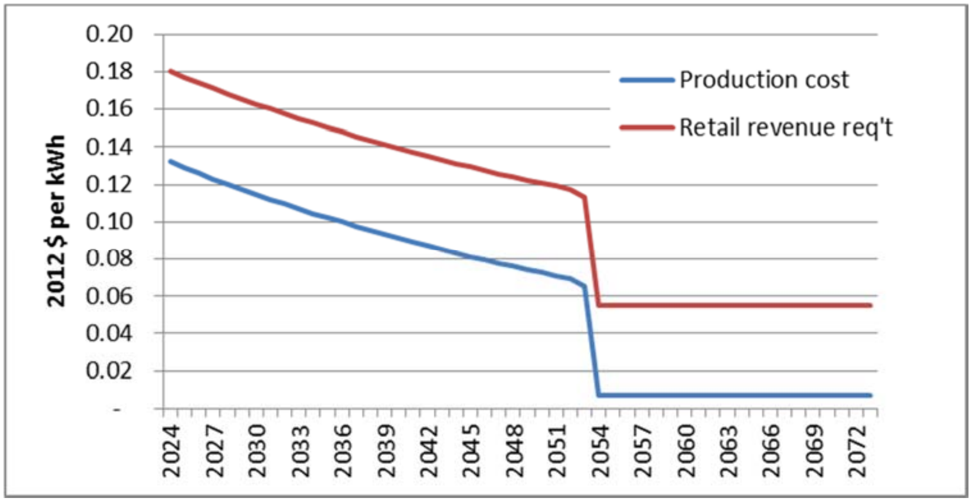
Susitna Case 1 results

Using the above assumptions the production cost of Susitna power in 2024 is 13 cents per kWh in 2012 dollars and the required retail rate is 18 cents. In subsequent years both numbers decline steadily because debt service cost is constant in nominal dollars and hence declining in 2012 dollars. Costs drop dramatically after 2053 when all debt has been retired. This progression is summarized in Table 5 and Figure 2.

Table 5. Susitna Case 1 cost of power

		2024	2035	2050	2073
Production cost per retail kWh sold	2012$/kWh	0.13	0.10	0.07	0.01
plus: Transmission, distribution, admin	2012$/kWh	0.05	0.05	0.05	0.05
Cost of power to retail customer	2012$/kWh	0.18	0.15	0.12	0.05

Figure 2. Susitna Case 1 cost of power



note: Hydro output would continue for many years after 2072.

Susitna Case 2 assumptions and results

Case 2 is based on a higher capital cost, a higher interest rate, and a requirement for additional revenue collected as debt service coverage. The capital cost value of $5.49 billion (6% higher than Case 1) is the high end of the 90% confidence interval range provided by AEA in its cost estimate presented in Febrary 2013. This value is The interest rates are assumed to be 6% for both long-term debt and construction financing, reflecting a possibility that the long-term rate will be higher than AEA assumes and that all financing will need to be done using a single long-term loan. In addition I have assumed the need for additional revenue equal to 25% of the debt service, as a more stringent alternative to the capital reserve fund.

The resulting production cost of Susitna power in 2024 is 21 cents per kWh in 2012 dollars and the required retail rate is 26 cents per kWh. The rates are significantly higher than Case 1 mostly due to the higher interest rate and debt service coverage requirement. In Case 2 retained earnings are accumulated and used to retire the remaining debt after only 25 years, causing costs to drop 5 years earlier than in Case 1. Table 6 summarizes the Case 2 results.

Table 6. Susitna Case 2 cost of power

		2024	**2035**	**2050**	**2073**
Production cost per retail kWh sold	2012$/kWh	0.21	0.17	0.01	0.01
plus: Transmission, distribution, admin	2012$/kWh	0.05	0.05	0.05	0.05
Cost of power to retail customer	2012$/kWh	0.26	0.21	0.05	0.05

Susitna Case 3 assumptions and results

Case 3 is based on a lower capital cost and a lower interest rate than Case 1. The capital cost value of $4.48 billion (14% lower than Case 1) is the low end of the AEA 90% confidence interval range. The interest rates are assumed to be 4% for long-term debt and 2% for construction financing, reflecting a possibility that the long-term rate will be lower than AEA assumes for its base case. As in Case 1, the capital reserve fund is used as the mechanism to protect bondholders.

The resulting production cost of Susitna power in 2024 is 10 cents per kWh in 2012 dollars and the required retail rate is 15 cents per kWh. The rates are lower than Case 1 due to the lower capital cost and lower interest rate. Table 7 summarizes the Case 3 results.

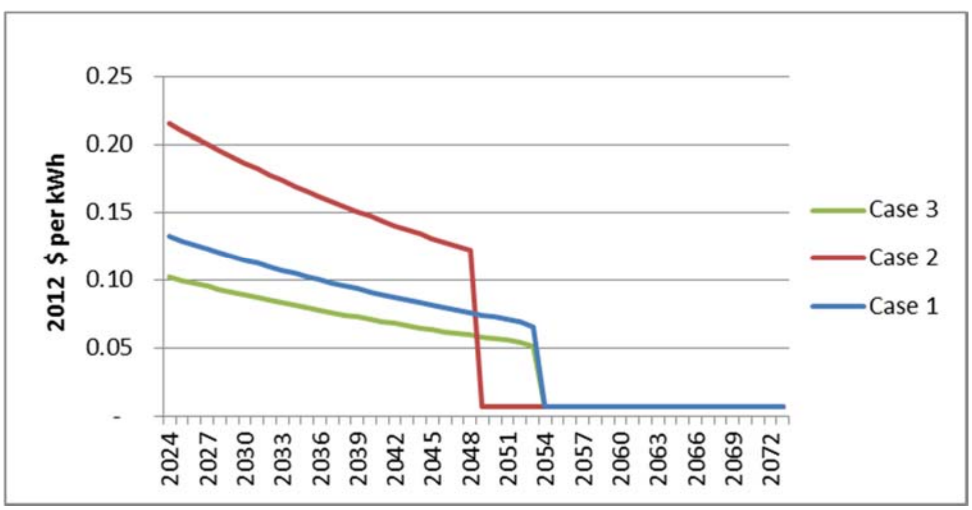
Table 7. Susitna Case 3 cost of power

		2024	2035	2050	2073
Production cost per retail kWh sold	2012$/kWh	0.10	0.08	0.06	0.01
plus: Transmission, distribution, admin	2012$/kWh	0.05	0.05	0.05	0.05
Cost of power to retail customer	2012$/kWh	0.15	0.13	0.10	0.05

Comparison of Susitna costs across cases

Figure 3 summarizes the projected Susitna power production costs developed above. The graph displays values for only the first 50 years of operation; hydro output would continue for many additional years.

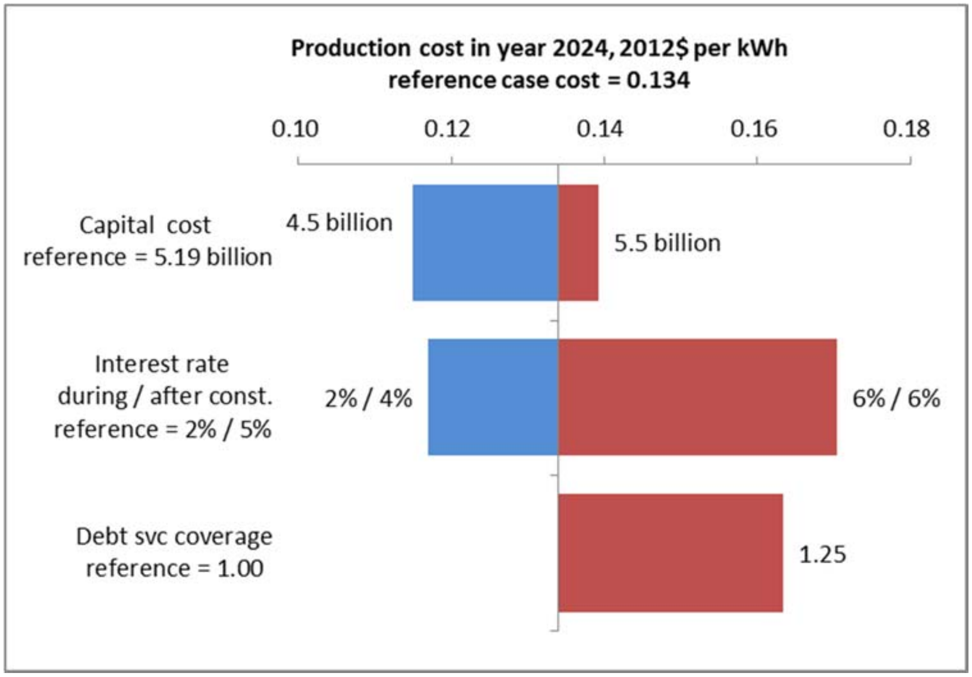
Figure 3. Susitna production cost comparison



note: Hydro output would continue for many years after 2072.

Further insight into the effect of different assumptions on the resulting costs is provided by Figure 4, which shows the change in production cost due to changes in several assumptions considered one at a time. The reference case cost of $0.13 per kWh is the Case 1 value. The lower and higher values for capital cost, interest rates, and required revenue in excess of debt service are the same as the values used in Case2 and Case 3, respectively. (There is no Case 3 lower value for debt service coverage.)

Figure 4. Sensitivity of Susitna production cost to individual assumptions



It should be noted that all three cases are intended to be reasonable cases and not "worst" or "best" or "most likely" cases. It is beyond the scope of this analysis to assign probabilities to any of these cases or to any others that would result from different assumptions. The point here is to recognize that on a large project such as the currently proposed Susitna-Watana dam there are inherent uncertainties, especially early in the development phase, and a range of costs and resulting rates is necessary to better understand the range of possible outcomes.

Natural gas comparison cases

In this section I develop low and high projections of the future price of natural gas and a plausible range of future gas-fired electricity costs. As noted in the introduction, the purpose of presenting these potential costs is simply to provide some context for the Susitna cost numbers. Natural gas is the logical alternative generation source for this purpose because it is the predominant source of electricity in the Railbelt, used for 73% of Railbelt net generation in 2011.[14] The natural gas cases are not intended to provide a head-to-head comparison of Susitna hydro with gas-fired generation.

Natural gas price projections

The critical factor affecting the cost of gas-fired power is, of course, the price of natural gas. Gas prices during the past two decades have been extemely volatile, even when measured at a single hub. For example, Figure 5 shows how the real price of gas at Henry Hub rose and fell and how the price delivered to U.S. electric utilities closely tracked the Henry Hub price.[15] The future price of gas delivered to an Alaska electric utility is arguably even more uncertain than the future price in an established market because by 2024 Alaska may become a major exporter of LNG from its North Slope resources, or it may remain as an isolated market served by gas from Cook Inlet and/or the North Slope (via a smaller “bullet”pipeline), or it may become an importer of LNG.[16]

[14] Alaska Energy Statistics 1960-2011. Data Tables. Accessed May 2013 at http://www.akenergyauthority.org/publications.html.

[15] Data from EIA Custom Table Builder, series NGHHUUS and NGEUDUS, deflated by the U.S. CPI-U price index.

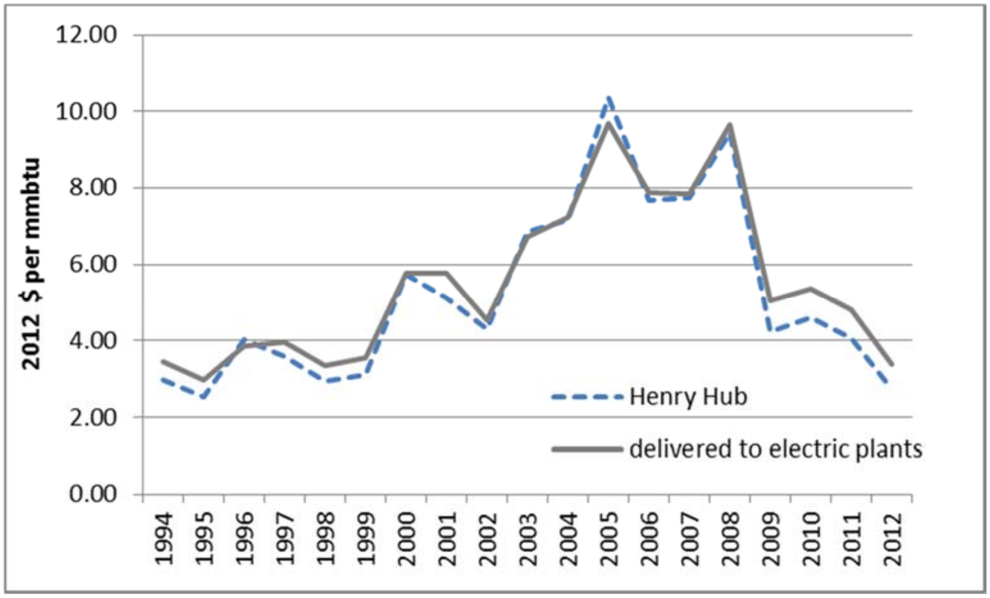
[16] For further discussion of Alaska’s natural gas supply uncertainties, see, e.g.:

Bradner, Mike. 2013. Cook Inlet gas woes: Meeting Southcentral Alaska’s Demand. Alaska Dispatch. April 10. www.alaskadispatch.com/article/20130410/cook-inlet-gas-woes-meeting-southcentral-alaskas-demand;

Scott, A. 2013. A Consideration of the Role of Commodity Prices In Project Solutions to Fairbanks’ Energy Cost Problem. Final report prepared for the Fairbanks--North Star Borough;

Bradner, Tim. 2013. Hilcorp says it can fill Southcentral gas needs through 2017. *Peninsula Clarion*. April 25. http://m.peninsulaclarion.com/news/2013-04-25/hilcorp-says-it-can-fill-southcentral-gas-needs-through-2016

Figure 5. Past U.S. natural gas prices



As a representative low projection I have adopted the gas price projections of Black & Veatch developed for the Railbelt Integrated Resource Plan (RIRP).[17] These projections are summarized in Table 6.

Table 6. Black & Veatch gas price projections

	2012	2024	2040	2050
2012 dollars per million btu	6.62	9.50	6.97	6.12

Although the Black & Veatch projections for 2012 are well above the Henry Hub price, they are currently tracking actual prices paid by Railbelt utilities fairly well. For example, 1) a price of $7.75 per million btu (or $8.25 delivered to the power plant) was the third quarter 2013 outcome of contract terms in the October 2012 contract between Chugach Electric and Hilcorp[18]; and 2) similar delivered prices, equivalent to between 99% and 102% of the Black and Veatch prices for years 2013 through 2017, were specified as

[17] http://www.akenergyauthority.org/RIRPFiles/Alaska_RIRP_Final_Report_120409/AlaskaRIRPFinalReport-Part2of6.pdf. Table 7-3

[18] Chugach Electric Association. 2013. Fuel and Purchased Power Rate Adjustment Filing: Tariff Advice No. 373-8. Filed May 30, 2013. http://www.chugachelectric.com/system/files/regulatory_affairs/ta373-8.pdf

price caps in the consent decree involving Hilcorp's acquisition of Marathon's assets that was approved by a state court in January 2013.[19]

As a representative high projection I developed a projection of future prices for LNG imported to Alaska from Asia.[20] I used Scott's equation[21] that relates the price of regasified LNG delivered to Cook Inlet to the price of crude oil in Japan:

regasified LNG at Cook Inlet [$/mmbtu] = 2.20 + 0.1545 * JCC [$/bbl]

where JCC is the "Japanese Customs Cleared" price of crude oil

Scott determined[22] that Alaska North Slope (ANS) crude oil prices could be used as a proxy for JCC in the above equation. Because EIA projects future Brent prices but not future ANS prices, I analyzed the Brent-ANS price relationship using monthly data from January 2004 through April 2013.[23] The Brent price averaged 44 cents higher than ANS but this difference was not statistically different from zero. The relationship is shown in Figure 6.

---

[19] Bradner, Tim. 2013. Hilcorp says it can fill Southcentral gas needs through 2017. Peninsula Clarion. April 25. http://m.peninsulaclarion.com/news/2013-04-25/hilcorp-says-it-can-fill-southcentral-gas-needs-through-2016

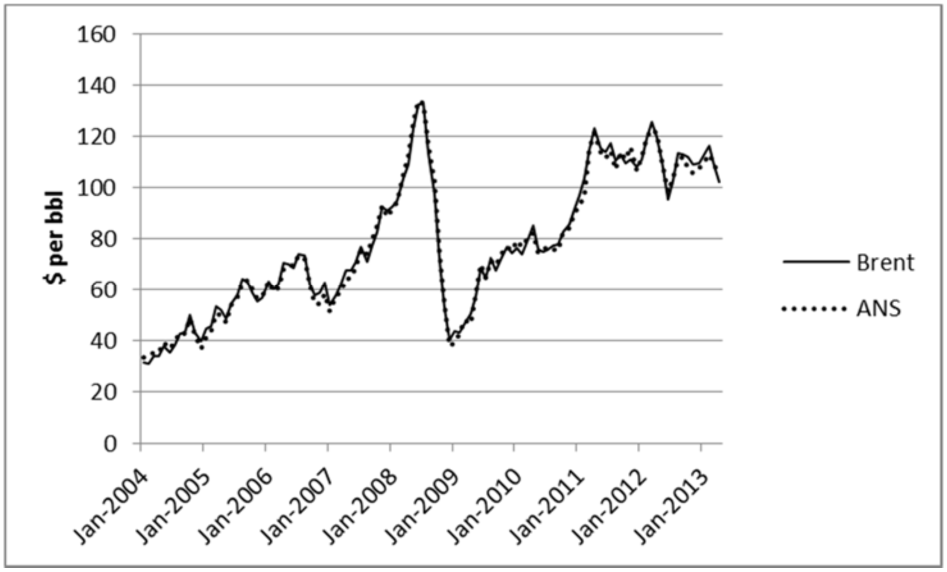
[20] I am grateful to a reviewer for suggesting this approach.

[21] Scott, A. 2013. A Consideration of the Role of Commodity Prices In Project Solutions to Fairbanks' Energy Cost Problem. Final report prepared for the Fairbanks--North Star Borough.

[22] Scott, *ibid*., p. 10.

[23] Brent data are from EIA. http://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm
ANS data are from Alaska Department of Revenue
http://www.tax.alaska.gov/programs/oil/prevailing/ans.aspx

Figure 6. Brent vs. ANS spot prices for crude oil



Based on this analysis the projected Brent crude price can substitute for JCC in the above equation. I used the reference case projections of Brent crude from the EIA Annual Energy Outlook (AEO) 2013.[24] Because the AEO projections only extend through 2040, I assumed a constant real price thereafter. The resulting projected prices for imported regasified LNG are summarized in Table 7.

Table 7. Gas price projections based on imported LNG

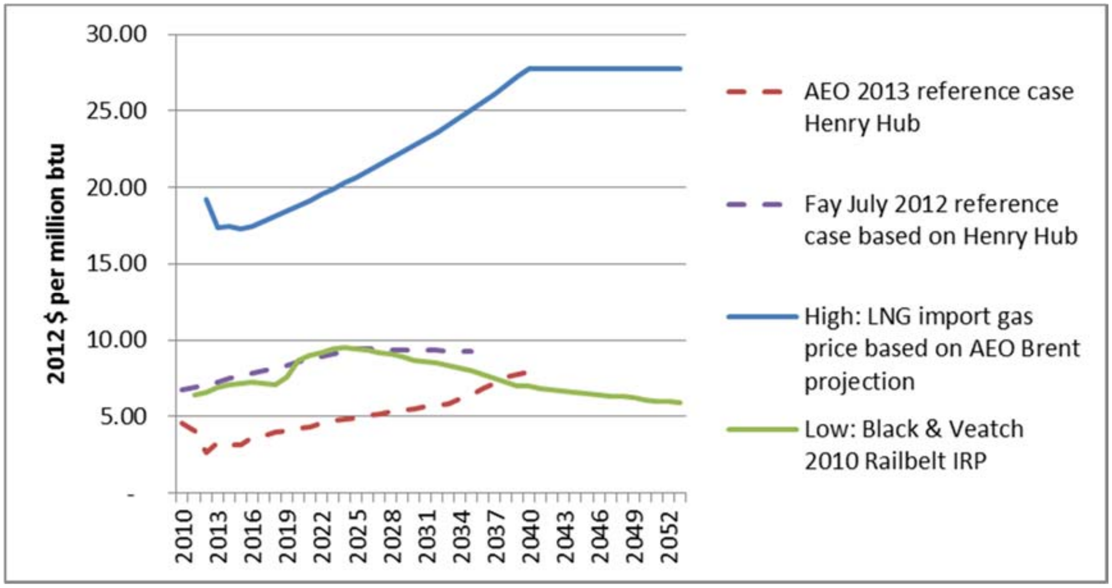
	2012	2024	2040	2050
2012 dollars per million btu	19.26	20.27	27.78	27.78

As a final step toward the goal of developing a resonable range of future gas prices, I checked the above projections against two others. The first is simply the projected Henry Hub prices from the AEO 2013 reference case.[25] The second is the Alaska Railbelt gas price projections prepared by Fay et al. and adopted by the AEA for the purpose of evaluating proposed renewable energy projects.[26] Those projections are based on future Henry Hub prices; however the authors prepared their own Henry Hub projections rather than relying on the AEO 2013 numbers.

[24] http://www.eia.gov/analysis/projection-data.cfm#annualproj . The U.S. GDP Deflator was used to convert 2011 dollars published in AEO to 2012 dollars.
[25] http://www.eia.gov/analysis/projection-data.cfm#annualproj
[26] Fay, G.; Villalobos Meléndez, A.; Pathan, S. 2012. Alaska Fuel Price Projections 2012-2035. Anchorage: Institute of Social and Economic Research. Prepared for Alaska Energy Authority. June.

Figure 7 summarizes the analysis by showing the low and high projections and the two projections used as validity checks.

Figure 7. Natural gas price projections



Natural Gas Case 1

Natural Gas Case 1 is intended to illustrate the lower end of the range of future Railbelt prices for gas-fired power. This case uses the low gas price projections – those from Black & Veatch. Based on the example of the recently completed Southcentral Power Plant,[27] I assume that a 180-MW high-efficiency combined cycle gas turbine could be built with a 4-year lead time beginning in 2020 and coming on line in 2024. (Three or four such plants could substitute for Susitna, but they would likely be built separately). The assumed capital cost is $2,000 per kW in year 2012 dollars. (The actual values for the SPP were $359 million for 183 MW of capacity, or $1,936 per kW.) The assumed financing mechanism is the same as for Susitna and the production cost and consumer rates are calculated in a similar way based on recovery of debt service. The Case 1 assumptions for this gas-fired plant are shown in Table 6.

[27] Chugach Electric Association. 2013. Community celebrates Southcentral Power Project. Press release, May 9.

Table 8. Natural Gas Case 1 Assumptions
(combined cycle gas-fired 180 MW plant)

Item	units	value
Capacity	MW	180
Annual capacity utilization factor		0.5
Annual energy output at busbar	MWh	788,940
Heat rate	btu/kWh	7,300
Overnight capital cost per kW	2012$/kW	2,000
Overnight capital cost for plant	2012$ billion	0.360
Lead time	years	4
Fixed O&M	2012$/kW-yr	14.60
Variable O&M	2012$/MWh	3.00
Annual O&M cost	2012$ billion	0.005
Debt-financed fraction		100%
Grant-financed fraction		0%
Long-term debt interest rate	nominal %	5.0%
Debt repayment period	years	30
Economic lifetime	years	30
Short-term debt rate (during construction)		2.0%
Financed reserve fund - ratio to debt service	ratio	1.00
Interest rate earned on short-run lending of FRF	nominal %	2.0%
Required debt service coverage ratio	ratio	1.00
General inflation rate	%	2.50%
Ratio of kWh sold to kWh at busbar		0.95
Trans, dist'n, admin cost	2012$/kWh	0.048
Natural gas price trajectory		low

Under these assumptions the resulting production cost of power is initially 11 cents per kWh. The price then falls steadily to 7 cents per kWh by 2050, due declining real debt service payments and declining real gas prices. Because the assumed economic life of the plant is 30 years, costs are calculated only through 2053. These results are summarized in Table 7.

Table 7. Natural Gas Case 1 cost of power

		2024	**2035**	**2050**
Production cost per retail kWh sold	2012$/kWh	0.11	0.09	0.07
plus: Transmission, distribution, admin	2012$/kWh	0.05	0.05	0.05
Cost of power to retail customer	2012$/kWh	0.16	0.14	0.12

Natural Gas Case 2

Natural Gas Case 2 is intended to illustrate the higher end of the range of future Railbelt prices for gas-fired power. This case uses the high gas price projections based on imported LNG tied to Brent crude. To align with Susitna Case 2, Natural Gas Case 2 uses a 6% interest rate for both construction financing and long-term debt. It also assumes that an additional 25% of debt service would be collected and held in reserve to protect bondholder interests. All other assumptions are the same as in Natural Gas Case 1.

In Natural Gas Case 2 the production cost of power increases from 21 cents per kWh in 2024 to 25 cents in 2039. The cost drops back to about 22 cents in 2046 as the long-term debt is retired early through the use of the accumulated retained earnings.

Table 8. Natural Gas Case 2 cost of power

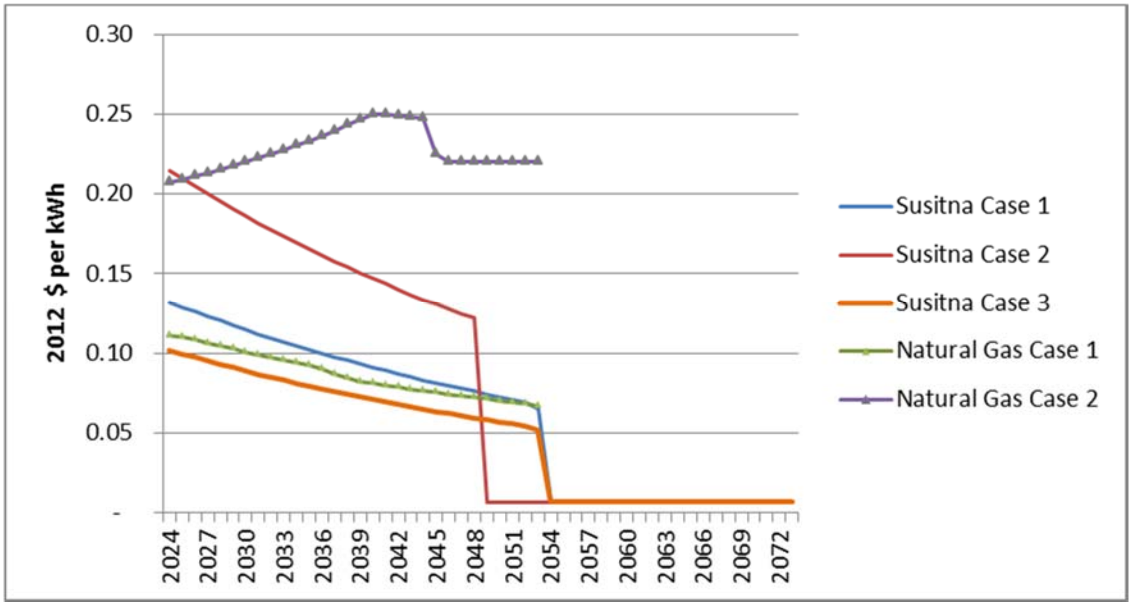
		2024	2035	2050
Production cost per retail kWh sold	2012$/kWh	0.21	0.23	0.22
plus: Transmission, distribution, admin	2012$/kWh	0.05	0.05	0.05
Cost of power to retail customer	2012$/kWh	0.26	0.28	0.27

Comparison of Susitna cases to natural gas cases

Figure 8 provides a summary of the results for production cost of power from all five cases. For the first 30 years, the Susitna Case 1 and Susitna Case 3 costs are broadly consistent with the low end of the range of gas-fired power costs, while Susitna Case 2 is initially consistent with the high end of that range but then drops steadily toward the bottom of the range. After 30 years, in 2054, Susitna power rates would drop significantly after long-term debt was retired. I have not attempted to project gas-fired power prices beyond 2054. Those prices would depend, mostly, on highly uncertain natural gas prices.

When evaluating these cases, it is important to remember that Susitna would be a single “lumpy” addition to the generation mix. It is unlikely that the Railbelt utilities will actually need 600 MW of new capacity in 2024. If Susitna hydro is substituted for existing gas-fired plants, only the cost of fuel will be saved in the short run. Capital costs of replacement or new gas-fired capacity may be avoided only at some future date. The only way to properly assess these factors is to conduct a rigorous integrated resource planning exercise in which the timing of all additions to generation is allowed to vary.

Figure 8. Comparison of cases: Production cost of power



Discussion

Costs not explicitly considered

This analysis considers some of the basic elements of the potential cost of the Susitna-Watana hydro project. Chief among these are the capital cost, the interest rate(s) on borrowed funds, and the ratio of required revenue collections to debt service (which affects mainly the *timing* of cost recovery). Some potentially important cost elements are not explicitly included. These include: 1) Fisheries impact mitigation measures; 2) Unmitigated fisheries impacts; 3) Transmission upgrades; and 4) Carbon taxes.

Fisheries impact mitigation measures could include both additional required infrastructure (fish passage mechanisms) and restrictions on water flows available for hydropower. Restricted water flows could reduce the annual energy output and drive up the cost per kWh. Unmitigated fisheries impacts could include reduced numbers of fish in the Susitna drainage and in Cook Inlet. Significant transmission upgrades costing more than $800 million have been recommended for the Railbelt grid in conjunction with the Susitna project (Electric Power Systems 2009). However, it is not clear to what extent the need for these upgrades is directly attributable to the project. Finally, I have not incorporated carbon taxes into the natural gas price projections. A carbon tax of

$100 per metric ton CO2 would add about 53 cents per million btu to the price of natural gas and about 4 cents per kWh to the price of gas-fired electricity.[28]

Risks associated with large hydro projects

This analysis does not directly quantify the potential risks of higher costs that are associated with such a large up-front capital expenditure. However, it is important for policy makers to consider such risks.

The report prepared for AEA by SNW (2010) identified and discussed the following risks.

- **Project Timeline.** SNW noted risks arising from the long lead time, from phased execution, from remote location, and from "unknown site or geological issues that could materialize" (p. 2)
- **Permitting and Licensing.** These processes could be delayed, driving up cost.
- **Development/Pre-construction.** "…These expenditures are rarely risks that investors will carry. Pre-construction costs would have to be paid by the State or an independent developer." (p. 3)
- **Construction Risk.** SNW noted multiple risk factors that could increase the project cost or time to completion. These include:
  1) price increases for materials or labor (commonly known as "escalation risk")
  2) difficulties securing supplies
  3) labor shortages or work stoppages
  4) "unanticipated and/or under-estimated construction challenges," (commonly known as "scope risk"), and
  5) "The risk that a contractor will fail to perform on its contractual obligations" (p. 3).[29]
- **Geological and Environmental Risk Factors.** SNW noted that "Susitna will demand extensive seismic and geological analysis prior to obtaining outside capital funding." (p. 3-4) They also found that Susitna "will incur environmental issues in the form of fish passage, changes in water quality and temperature, vegetation removal, wildlife habitat loss or alteration, and reservoir fluctuations. These risks may not be limited to the construction period. Post-construction environment risk could materialize due to an unanticipated environmental impact." (p. 4)

[28] This calculation assumes 0.053 tons CO2 per million btu of natural gas and a heat rate of 7,300 btu/kWh. CO2 coefficient from: http://www.eia.gov/oiaf/1605/coefficients.html.
[29] One reviewer has noted that a natural gas plant would be subject to escalation risk but probably not subject to scope risk because gas-fired power plants are a known and widely replicated technology.

- **Regulatory/Legal Risk Factors**. Referring to potential changes in rules and regulations, SNW found that "…it would be a mistake to proceed with either project under the assumption that there is no political risk." (p. 4)
- **Technology Risk**. SNW noted the risk that some other technology might render Susitna power uneconomic, and suggested that "This risk factor can be mitigated through the structure of the Power Purchase Agreement." (p. 4)

When considering these risks, it is important to remember that the State of Alaska, through the AEA, would bear all of the noncompletion risk during the development phase up to the start of actual construction. All development expenses would be paid by the state (they could not be financed through bond sales) and would be lost if the project was not built.[30]

Risks pertinent to Alaska as an energy producer

Policy makers also need to consider Alaska's relatively unique position with respect to global energy markets and prices. As an oil exporter Alaska gains, overall, from crude oil price increases. For example, in 2008 the price of oil increased but the State took in so much additional oil revenue that it was able to pay out $1,200 per person as a "resource rebate" to defray consumer petroleum costs (and natural gas and electricity costs, which were partly indexed to crude oil at the time) while still having billions of additional dollars for government spending.[31]

If Alaska becomes a major gas exporter due to construction of a large pipeline from the North Slope, then a run-up in global natural gas prices over the relevant time frame of Susitna (roughly from 2024 through 2054) would likely be very good for the economy of Alaska and for state government as a fiscal entity. The economy would be so strong that consumers, perhaps with state assistance, could afford to pay high prices for gas-fired power. Conversely, if gas prices were low during this period, the economy would be weak and the billions spent on a large hydro project would be yielding few benefits relative to cheap gas-fired power.

Although Alaska is not currently a gas exporter, global gas prices may help determine *whether* and *when* Alaska becomes a gas exporter in the first place. High global gas prices could be good for Alaska because they enable the state to become a gas exporter and to then get rich from selling gas. Low global gas prices could be very bad for Alaska because they might prevent the state from exporting any gas, or because they might reduce the revenue from such exports as do occur.

[30] I am grateful to an anonymous reviewer for making this point.
[31] http://www.adn.com/2008/08/08/487182/legislature-passes-1200-rebate.html

Arguably Alaska's worst possible downside risk is that of very low oil and global gas prices coupled with a lack of available financial assets to provide substitute revenues. This was precisely the situation experienced in 1986 when the price of oil plummeted. The result was the worst recession in the state's history, during which 10% of all jobs and half of all construction jobs were lost, and the state's population dropped by more than 15,000.[32],[33]

The crucial point of this brief discussion is that as long as Alaska is a net seller of oil and gas, our price risk profile is likely to be quite different from that facing most other places. In most other places, hydro projects will likely reduce the price risks of gas-fired power generation. But if a large hydro project is built in Alaska and if gas prices are high, Alaskans could benefit from both low-cost power and high export revenues. But if a large hydro project is built and gas prices are low, Alaskans could be stuck with relatively high-cost power, low export revenues, and a shortage of financial wealth to shore up its fiscal position and economy. Put another way, a large investment in hydro could offer the prospect of a greater up-side payoff (if gas prices are high) and a greater down-side loss (if gas prices are low).

At the moment, we don't know whether Alaska is destined to become a gas exporter[34] and we don't know what kinds and amounts of financial commitments the state would need to make to build the Susitna project. Such required commitments could be significant -- perhaps running into billions of dollars – and they could preclude the ability to undertake other large projects or meet other state needs. It will be important to keep in mind both the potential cost and the potential risks of all large energy projects competing for Alaska's scarce state dollars.

---

[32] Goldsmith, S. 1987. Alaska's Economy: What's Ahead. *Alaska Review of Social and Economic Conditions* XXIV (2), pp. 2-17.
http://www.iser.uaa.alaska.edu/Publications/formal/arsecs/ARSEC_XXIV_2_AKEconomy_What%27s_Ahead.pdf

[33] Population data from Alaska Department of Labor.
http://laborstats.alaska.gov/pop/estimates/data/ComponentsOfChangeAK.xls

[34] For further discussion of the uncertainties and challenges facing Alaska gas exports, see:
http://www.rbnenergy.com/some-plans-are-bigger-than-others-alaska-lng-exports

http://www.arcticgas.gov/Alaska-Natural-Gas-Pipeline-Project-History

http://www.arcticgas.gov/guide-to-alaska-natural-gas-projects-fact-sheet

References

Alaska Energy Authority. [no date]. Susitna Watana Project 2011 Report to the Legislature. http://www.susitna-watanahydro.org/Docs/Report_to_the_Legislature_2011.pdf

Alaska Energy Authority. 2010. Railbelt Large Hydro Evaluation Preliminary Decision Document. November 23, 2010. Accessed 3/9/12 at: http://www.susitna-watanahydro.org/Docs/AEA_2010_PrelimDecDoc.pdf.

Chugach Electric Association. 2012. 2011 Annual Report. http://www.chugachelectric.com/sites/default/files/annual_reports/2011_annual_report_for_website.pdf

Chugach Electric Association. 2012. TA-347-8. Semi-annual simplified rate filing. http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=253d3650-b7c6-4e59-98c0-8fca94ea835d

Electric Power Systems. 2009. Susitna Hydro Transmission Study. EPS Job #09-0254 Prepared for: Alaska Energy Authority

Regulatory Commission of Alaska. TARIFF ACTION MEETING MEMORANDUM dated May 3, 2012. Subject: TA347-8 Chugach Electric Association, Inc.'s SRF Tariff Filing for the Test Year Ended December 31,2011. http://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=35B2E590-ADDB-4962-8ECF-0DF854E701AF

SNW. 2010. Hydroelectric Project Risk Analysis & the Bradley Lake Funding Model Summary Report. ftp://ftp.aidea.org/RailbeltLargeHydro/RLHRiskAnalysis.pdf