Oil & Gas Infrastructure in Cook Inlet, Alaska

A Potential Public Liability?

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September 2013

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Oil rigs and pipelines at Cook Inlet.
What will happen if this infrastructure is abandoned, how much will it cost to clean it up and who will pay?

In brief:

- In Alaska's Cook Inlet, oil and gas production has been on the decline for decades and, until recently, was presumed to be nearing the end of its economic life. However, in the past five years, there has been a "renaissance" in exploration and production, as technological advancements allow operators to extract resources from older fields. These advanced recovery methods require new infrastructure beyond the existing oil wells, platforms, pipelines, and onshore processing facilities now in place.

- The existing oil wells, platforms, pipelines, and onshore processing facilities are now nearly 50 years old are starting to be shut in. As they shut in, oil and gas companies are required to initiate plans for dismantling and removal of key infrastructure on state-owned land and to restore affected marine and shoreline ecosystems (DR&R).

- However, as demonstrated in Alaska and other states, this obligation is often disputed, unclear or not met, leaving states and federal taxpayers with a potential financial liability for cleaning up the damage left behind. In Alaska, bond financing provides the State with funds for DR&R, which add to any private sector funds and covers costs should companies default on their obligations.

- Records provided by Alaska Department of Natural Resources (ADNR) staff and other public records cited by the General Accounting Office indicate that the value of DR&R funding committed through State bonding and included in ADNR databases to be roughly $46 million. Additional bonding documented by Division of Oil and Gas staff but not included in ADNR databases indicates an additional $140 million in performance bonds and guarantees.

- In contrast, the total costs of DR&R for 16 offshore platforms and 160 miles of oil pipelines in Cook Inlet will range between $402 million and $1.11 billion. Adding gas pipelines and other infrastructure with more ambiguous DR&R requirements would greatly increase this cost estimate and the associated funding gap. Thus, DR&R funding available to the State through bonds may represent no more than 25-50% of total anticipated costs.

As a result, this report makes the following preliminary observations and recommendations:

- Bonding and related surety obligations for oil and gas infrastructure need enhanced clarity and predictability to best serve the interests of industry, government and Alaskans alike;

- Currently, it is difficult and at times impossible to understand the amounts obligated by oil and gas companies for DRR operations; as a result, new DNR rules should promote transparency to allow members of the public, agency personnel and stockholders to better understand DRR liabilities;

- Regardless of a corporation's financial fitness, the recent financial crisis has shown that there is no such thing as "too big to fail." As a result, any new bonding or surety strategies must ensure all companies with DRR obligations, regardless of their financial wherewithal, set aside the resources needed to meet their DRR responsibilities.

- Bonding requirements should not be based on a schedule of nominal fees, but the actual expected costs of DR&R for each facility, pipeline, platform, or other infrastructure element.

Background

The oil and gas industry in Cook Inlet is in flux. Oil and gas infrastructure expanded rapidly after commercial production began in the late 1950s. Operators drilled a record 35 wells in 1966 and had installed 14 offshore production platforms by 1968 (Rothe 2005, Kenai Offshore Drilling 2013). Oil and gas production reached a record 300 million barrels of oil equivalent (MMBOE) in 1970. Since the late 1960s, however, just two platforms were installed respectively in 1986 and 2000. In 2006, operators drilled just five new wells and recovered 50 MMBOE Regarding the outlook, one 2009 study noted that "new production is simply not outpacing natural field decline" even as two jack-up rigs prepared for deployment to aid with new exploration (DEAC 2009; Bradner 2013).

The two jack-up rigs – spurred by generous tax credits and other incentives—were an indication, however, that a new round of oil and gas development was on the horizon. Indeed, in the past five years, there has been a "renaissance" of exploration and development according to industry executives (Klouda 2013). For example, in late 2012 Cook Inlet Energy LLC announced plans to build the $50 million, 29-mile Trans-Foreland Pipeline for transporting crude oil across Cook Inlet to the Tesoro Refinery to avoid the more risky tanker transports used today. The expectation is for greater production along the western shores to justify the investment (Loy 2012). Hilcorp's acquisition of Cook Inlet gas and oil assets will ensure additional supplies from older fields thought to be tapped out. Hilcorp specializes in technological innovations that help wring "oil and gas out of legacy fields abandoned by larger companies" (DeMarban 2013).

All this new activity is bolstered by new, more optimistic assessments of recoverable reserves by USGS and private companies. For the Cook Inlet region, the USGS now estimates that total undiscovered but technically recoverable oil resources range between 108 and 1,359 million barrels of oil (MBOE) and between 4,976 and 39,737 billion cubic feet (bcf) of gas – a significant increase over its 1995 projections

(USGS 2011). In 2013, Buccaneer Energy revised its estimates of proven oil reserves in the North Cook Inlet unit upward by 54 percent.[1]

Regardless of these new discoveries or investments in exploration and development, there are ongoing concerns about the future of ageing industry infrastructure. Miles of pipeline, docking facilities, refineries, and offshore production platforms become irrelevant if production does not justify their continued operation or if they are deemed obsolete in the face of new, more efficient and effective technologies.

A complicated framework of state and federal policies establish the obligations and processes for dismantlement, removal, and restoration (DR&R), which could carry a high cost for companies and potentially Alaska residents. In particular, bonding requirements cover only a portion of the full cost of DR&R, and if companies go bankrupt or otherwise default on these obligations, the public could be left with the resulting liability.

In the past, a lack of specific requirements for cleanup and restoration led to the abandonment and inadequate cleanup of about 80 wells drilled on federal lands in what is now known as the National Petroleum Reserve in Alaska (Lazaroff 2002). As infrastructure in Cook Inlet continues to age and become obsolete, there are concerns that this scenario could be repeated.

To provide a preliminary estimate of the costs of DR&R for offshore platforms and pipelines in Cook Inlet and comparison to the likely value of DR&R funding available to the State, Cook Inletkeeper partnered with Center for Sustainable Economy (CSE) for a preliminary analysis of five relevant factors:

1) existing extent of industry infrastructure relevant to DR&R requirements in Cook Inlet;
2) age and life expectancy of the infrastructure;
3) state and federal laws and rules applicable to bonding and DR&R;
4) the value of bonds or other surety amounts committed for DR&R when operations cease; and
5) estimated actual DR&R costs needed to remove the infrastructure.

This preliminary report addresses each of these elements by relying on publicly available information. Greater precision in the figures and legal framework reported here would be possible with cooperative agreements from the companies that maintain fossil fuel infrastructure in Cook Inlet and the State of Alaska to share data and help frame a subsequent, more refined analysis.

Extent of Fossil Infrastructure in Cook Inlet

Fossil fuel infrastructure in Cook Inlet is well developed and documented (DEAC 2009; DOG 2009; Robertson and Parker Horn 2000). As of 2010, major components included:

- Sixteen offshore platforms producing oil and gas, including all process equipment, facility piping and associated pipelines. These platforms include 247 wells, of which 109 are shut-in. Four platforms are currently in lighthouse mode (e.g., wells shut in, production facilities cleaned, platforms decommissioned but navigational aids intact).

- Twenty-one onshore gas production facilities, including all process equipment, facility piping and associated pipelines. Six facility areas are not currently producing.

[1] Reported in Alaska Business Monthly, June 21st, 2013, available online at: http://www.akbizmag.com/Alaska-Business-Monthly/June-2013/Buccaneer-Energy-Reserves-Resources-North-Cook-Inlet-Deep-Oil-Rights/.

- Five onshore oil and gas processing facilities, including East Forelands Facility, Granite Point Tank Farm, Trading Bay Production Facility, West McArthur River Facility, and Kustatan Facility as well as associated process equipment, facility piping and pipelines.

- Drift River Marine Terminal and associated Christy Lee Platform, including all process equipment, storage tanks, facility piping and associated pipelines up to the berth loading arms.

- Oil and gas pipelines. Epstein (2002) identified over 1,000 miles of transmission pipelines, gathering lines, and natural gas distribution pipelines. Of these, a 2000 inventory of oil pipelines estimated 150 miles of pipeline length, of which 84 miles are offshore (Robertson and Parker Horn Company 2000). Since that time, the Osprey offshore platform and associated pipelines were put in place. This infrastructure includes one oil, one gas, and one water pipeline roughly two miles in length each and a set of onshore pipelines totaling 16.2 miles in length (Goff 2003).[2] Of these, roughly 10 are for oil, bringing the Cook Inlet total for oil to 160 miles.

This infrastructure is distributed throughout Cook Inlet but concentrated in the region bordered by the Kasilof to the southeast and Tyonek to the northwest (Appendix 1).

Age and Life Expectancy of the Infrastructure

Data describing the date of installation for both offshore platforms and oil pipelines is publicly available. These data are reproduced in Tables 1 and 2 below. Table 1 describes each of the 16 offshore platforms by name, 2009 operator, and year installed. The table also indicates the platform's status as of 2009 in terms of active and shut-in wells (DEAC 2009). Since that time, Hilcorp Energy LLC has taken control of Marathon Oil Company's Cook Inlet assets, mostly gas producing wells, as well as the Chevron Corporation Inlet properties that include the producing offshore oil platforms.

Table 2 describes the documented oil pipelines in Cook Inlet with respect to operator, pipeline type, pipeline length, and year of installation (Robertson and Parker Horn 2000; Goff 2003). Additional information on all pipelines – oil and gas – can be found in Epstein (2002). The Alaska Department of Environmental Conservation (ADEC) distinguishes two types of oil pipelines: crude oil transmission pipelines and facility pipelines. The difference is regulatory in nature, but does not affect CSE's estimates of DR&R costs since structurally there are few if any differences. As of 2005, Union (Unocal) merged and is a wholly owned subsidiary of the Chevron Corporation. As noted above, Hilcorp now controls most of Chevron's assets. Hilcorp presumably now operates Chevron pipelines in the Cook Inlet Basin, although legally Union is still listed as the owner. As such, Table 2 retains the original pipeline operator's name.

Given historical declines in Cook Inlet oil and gas production, there are questions as to how long this infrastructure will continue to be useful. Already, four offshore platforms are in lighthouse mode and seven oil and gas fields or units are not producing (DEAC 2009). While predicting the life expectancy of oil and gas infrastructure is a difficult and complex task, it is reasonable to assume that the useful life of this infrastructure is related to the reserves that remain and the annual depletion rate.

As late as 2009, experts presumed that oil and gas production in Cook Inlet was nearing the end of its useful life. These 2009 projections demonstrated that most existing fields would cease production in the 2015 to 2021 period if then-current production continued and no new reserves were located. According to the Alaska Divsion of Oil and Gas, just 109 MBOE oil and 1.5 trillion cubic feet of natural gas were left

[2] See also Conam construction descriptions available online at: http://conamco.rapidsys.com/index.php?option=com_content&task=view&id=17&Itemid=45.

to recover as of the 3rd quarter of 2007. The 2006 depletion rates were six MBOE oil and 196 bcf of gas. Applying these rates to the 2008 to 2013 period suggests that just 47 MBOE oil and 379 bcf gas remain. Current production rates would deplete oil reserves by 2021 and gas reserves by 2015 (DOG 2009).

However, since that time, and as noted previously, there has been a new wave (renaissance by some accounts) of oil and gas exploration and development in Cook Inlet, bolstered in part by new estimates of technically recoverable reserves by the USGS and private companies. The USGS estimates are at least two times greater for oil and thirteen times greater for gas than those reported in Table 3. Thus, attempts to forecast the life expectancy of Cook Inlet oil and gas infrastructure based on estimated reserves and depletion rates is fraught with uncertainty.

Regardless, one thing is clear: the first wave of oil and gas infrastructure installed in Cook Inlet in the 1960s has far exceeded its design life. As noted by Visser (1989), "[t]he initial development plans for the Cook Inlet fields anticipated an economical field life of about 20 years and the platform designs were based on this assumption." This casts doubt on whether or not renovations and refurbishments are possible – as evidenced by plans to replace ageing and leaky pipelines with new ones and the current lighthouse status of four offshore platforms. Thus, issues over DR&R and whether or not adequate financial resources exist to restore Cook Inlet's marine and coastal resources to their natural state remain a timely issue for consideration.

Table 1: Cook Inlet Offshore Platforms
(Alphabetical order by facility name)

Facility name	Operator (2009)	Active wells	Wells shut-in	Year Installed
Platform A	XTO Energy	15	2	1964
Platform Anna	Chevron*	12	3	1966
Platform Baker	Chevron*	1	13	1965
Platform Bruce	Chevron*	7	5	1966
Platform C	XTO Energy	12	4	1967
Platform Dillon	Chevron*	0	9	1966
Platform Dolly Varden	Chevron*	17	20	1967
Platform Granite Point	Mobil/ Chevron*	8	3	1966
Platform Grayling	Chevron/ Marathon*	20	15	1967
Platform King Salmon	Chevron/ Marathon*	12	13	1967
Platform Monopod	Chevron/ Marathon*	2	0	1966
Platform Osprey	Pacific Energy Resources	2	3	2000
Platform Spark	Marathon*	0	6	1968
Platform Spurr	Chevron/ Marathon*	8	8	1968
Platform Steelhead	Chevron/ Marathon*	24	4	1986
Platform Tyonek	Conoco-Phillips Alaska	7	0	1968

** By spring of 2013, Hilcorp had acquired most of Marathon's and Chevron's assets in Cook Inlet.*

State and Federal Laws and Rules Applicable to Bonding and DR&R

This section discusses the regulatory requirements related to DR&R with an emphasis on the bonding requirements. While there are dozens of laws, rules and regulations relevant to the permitting and safe operation of pipelines and onshore processing facilities, DR&R obligations are not explicit (See, e.g. Robertson and Parker Horn Company 2000). In contrast, DR&R obligations with respect to offshore platforms and associated infrastructure are explicit. Both state and federal regulations apply.

Table 2: Cook Inlet Oil Pipelines

Original Operator	ADEC Class	Length (miles)	Installed
Kenai Pipeline	Facility pipeline	19.2	1960
Cross Timbers	Facility pipeline	7.0	1965
Kenai Pipeline	Facility pipeline	3.9	1965
Unocal	Facility pipeline	2.5	1965
Cook Inlet Pipeline	Crude oil pipeline	42.0	1966
Cook Inlet Pipeline	Facility pipeline	3.6	1966
Unocal	Facility pipeline	6.0	1966
Unocal	Facility pipeline	1.6	1966
Unocal	Facility pipeline	9.0	1966
Cross Timbers	Facility pipeline	2.2	1967
Unocal	Facility pipeline	6.0	1967
Unocal	Facility pipeline	7.0	1967
Unocal	Facility pipeline	5.7	1967
Marathon	Facility pipeline	7.2	1968
Unocal	Facility pipeline	8.4	1968
Unocal	Facility pipeline	1.6	1974
Tesoro	Facility pipeline	8.3	1974
Tesoro	Facility pipeline	1.0	1983
Unocal	Facility pipeline	6.5	1986
Forcenergy	Crude oil pipeline	1.3	1993
Forest Oil (est.)	Facility pipeline	2.0	2002
Forest Oil (est.)	Facility pipeline	8.0	2002
	Total:	160.0	

State of Alaska laws and regulations

Of the two sets of laws and regulations that could apply to offshore production platforms in Cook Inlet, those for the State of Alaska are more relevant than those for the federal government. In the U.S. federal system, federal laws establish a baseline for compliance that states can exceed. In addition, all 16 offshore production platforms lie in state waters. Thus, there are no commercial, permanent platforms in the defined federal waters of Cook Inlet that would be subject only to the federal laws for production on the outer continental shelf. Federal laws remain relevant however, since a lease sale is scheduled for Cook Inlet in 2016 under the Five Year Outer Continental Shelf Oil and Gas Leasing Program for 2012 to 2017 (BOEM 2013).

The state laws and regulations are best explained according to the entities that implement and enforce them. The Alaska Oil and Gas Conservation Commission (AOGCC), administered within the Alaska Department of Administration, holds responsibility for protecting the subsurface integrity of oil and gas fields during well exploration and production phases. The AOGCC receives authority from the Alaska Oil and Gas Conservation Act, which also provides authority for many of the Commission's regulations. The regulations affecting DR&R span from 20 AAC 25.005 (drilling permit) to 20 AAC 25.172 (offshore location clearance) and cover bonding, abandonment, and plugging among other requirements.

Regarding bonding, an operator may be required to provide a third-party surety bond for more than $100,000 for a single well or $200,000 for all of its wells in the State. The bond "ensure[s] that each well is drilled, operated, maintained, repaired, and abandoned and each location is cleared…" according to requirements established further in the chapter. In addition, the operator must abandon wells within one year of the permanent cessation of recovery activity in the field or expiration date of the lease and sever wellhead equipment and casing at three feet below the original ground level. To date, most offshore production platforms have neither ceased activity nor faced expired leases. However, Chevron (now Hilcorp) provided the AOGCC a timetable for abandoning their Baker and Dillon platforms in May 2010. The company forecasts full removal in 2019.

The Alaska Department of Natural Resources (ADNR) has additional regulatory authority over DR&R operations. Established under the authority of the Alaska Land Act, 11 AAC 83.160 requires lessees to provide a bond for at least $10,000 to ADNR before commencing operations. Alternatively, the lessee may provide a statewide bond for $500,000. At his discretion, the ADNR Commissioner may require bonds for a greater amount. In 11 AAC 82, the State requires lease agreements to include the necessary bond amount and defines the conditions for lease transfers for companies that go out of business, sell their assets, or transfer the lease. For some leases, unit agreements establish DR&R requirements in excess of lease agreements. Thus, the lease and unit agreements provide the most accurate information on bond amounts to cover operations on the 16 offshore production platforms.

As documented by GAO, the ADNR can also require an unusual risk bond in addition to single well and statewide bonding requirements.[3] State of Alaska regulations provide the ADNR Commissioner with the discretion to require additional financial assurances based on, among other factors, the degree of risk involved for the operations proposed or conducted on the lease including the financial background of the lessee (GAO 2002).

Lease agreements

CSE requested and obtained lease agreements for the 16 offshore production platforms from the State of Alaska (see reference section). All leases except one (i.e., lease number 381203 for the Osprey platform) are dated in 1962 and thus have similar bond requirements. Each lease includes the land tracts, their combined acres, and bonding requirements prior to the lease issuance and commencing drilling operations. Prior to lease issuance, the lessee must provide a bond of $2.00 for each acre with the total amount exceeding $1,000. In addition, prior to commencing drilling operations, the lessee must provide a bond of $5,000 per well or $100,000 for all of the lessee's wells in the State. Requirements for the Osprey platforms are slightly higher, at $5.00 per acre up to a $10,000 minimum and statewide bond equal to the bond requirements in relevant regulations (i.e., 20 AAC 25.005 to 20 AAC 25.172 and 11 AAC 82). Table 4 lists the bond requirements in each lease that includes an offshore production platform.

Both the lease agreements from 1962 and the Osprey agreement from 1994 contain other bond conditions as well. If the State determines that greater bond amounts are necessary to cover the risk and operations of the lease activities, it may require the lessee to hold that additional bond. A statewide bond does not substitute for the additional amount. For example, if the per acre amount before leasing equals $10,000 but the State requests $20,000, the lessee is not covered by a $100,000 statewide bond. Finally, for wells

[3] The Alaska DNR recently issued a discussion paper laying out a proposed risk-based bonding strategy, and will hold a public workshop September 9, 2013 to take comments on the proposal. *See* Possible Financial Strength Measures for Offshore Platforms South of the 68th Parallel (August 23, 2013), available at: http://dog.dnr.alaska.gov/AboutUs/Documents/PublicNotices/Offshore_DRR_Briefing_Document_08_23_13PM.pdf

located in areas covered under unit agreements, the wells are covered by any statewide bond for those unit agreements. The bond amounts add to any private-sector financing reserved for DR&R. Since 1962, platforms transfers, company sales, negotiations among unit partners and other factors have influenced the amount of bonds that companies hold for DR&R.

Table 4: Bond Requirements in Leases that Include Offshore Platforms

Platform	Date installed	Lease number	Acre-based bond	Before-drill bond options	
				Per-well	Statewide
Anna	1966	18742	$10,120	$5,000	$100,000
Baker	1965	17595	$10,212	$5,000	$100,000
Bruce	1966	18742	$10,120	$5,000	$100,000
Dillon	1966	18746	$6,400	$5,000	$100,000
Dolly Varden	1967	18729	$6,170	$5,000	$100,000
Granite Point	1966	18761	$10,178	$5,000	$100,000
Grayling	1967	17594	$10,232	$5,000	$100,000
King Salmon	1967	18772	$7,680	$5,000	$100,000
Monopod	1966	18731	$7,680	$5,000	$100,000
Osprey	2000	381203	$19,200	N/A	N/A
Spark	1968	17597	$10,240	$5,000	$100,000
Spurr	1968	17597	$10,240	$5,000	$100,000
Steelhead	1986	18730	$7,680	$5,000	$100,000
Tyonek	1968	17589	$10,000	$5,000	$100,000
XTO A	1964	18754	$7,492	$5,000	$100,000
XTO C	1967	18756	$10,240	$5,000	$100,000

Finally, the lease agreements explain conditions related to other DR&R processes. The leases from 1962 include provisions for the State to cancel the lease. Within 60 days of a notice for failure to comply with lease requirements, the State may revoke a lease agreement if no working wells are on the land tracts. If the land tract includes working wells, only judicial proceedings may revoke the lease agreement. In addition, upon termination, the lessee has six months to remove its property from the land tract unless the State provides additional time. The 1994 lease agreement contains similar conditions with one exception. The lessee has one year to remove its property and must rehabilitate the site to the State's satisfaction. If the State prefers, the lessee may also abandon infrastructure such as roads, pads, and wells and become absolved of any further DR&R responsibility.

Unit agreements

The Alaska permitting process recognizes two types of access and recovery agreements. In addition to leases for tracts of land, the State also awards unit agreements for tracts that drain a common reservoir. The unit agreements allocate production shares. Lessees under well lease agreements may unite and form unit agreements when it serves the interest of companies, the State, and the general public.

In addition to the lease agreements, CSE requested and obtained unit agreements for the units that contain offshore production platforms (see references section). As follows, the North Middle Ground Shoals unit includes the Baker offshore production platform; South Middle Ground Shoals unit includes Dillon; North Trading Bay unit includes Dolly Varden, Grayling, King Salmon, and Steelhead; South Granite Point unit includes Granite Point; North Cook Inlet unit includes Tyonek; and the Redoubt unit includes the Osprey offshore production platform. Of the unit agreements, those for North Middle Ground Shoals, South Granite Point, and Redoubt have a similar format that includes DR&R provisions (Rothe 2005).

Those unit agreements provide lessees of their land tracts with one year to remove property upon termination of the agreement. They also provide the State with flexibility in requesting that some minimal infrastructure (e.g., roads, pads, wells) remain on site and absolves the lessees of further DR&R responsibility when those requests are made. Thus, those unit agreements extend some DR&R conditions of the lease agreement for the Osprey offshore production platform to the Baker and Granite Point platforms. Since its lease and unit agreements contain similar provisions, the unit DR&R requirements will have little effect on the Osprey platform.

Federal laws and regulations

While all current offshore production platforms are located in State waters, federal DR&R requirements remain relevant. The U.S. Department of the Interior Bureau of Ocean Energy Management (BOEM) develops and administers the Outer Continental Shelf Oil and Gas Leasing Five-Year Program (Program). Due to lack of industry interest, the Department of the Interior has not held a lease sale since 2004 when no companies submitted bids (BOEM 2011). However, the 2012 to 2017 Program plans a "special-interest" sale for planning area 244 in 2016 (BOEM 2013). In a special-interest sale, BOEM requests that companies nominate tracts within planning areas where they may have a bid interest. If no companies express interest, BOEM does not hold the sale.

After successfully bidding on a tract, receiving a lease, and implementing an offshore production platform, a company would need to comply with federal regulations for offshore development. Bonding requirements in the Code of Federal Regulations (CFR) span 30 CFR 556.52 to 30 CFR 556.59 and 30 CFR 250.1490 to 30 CFR 250.1491. Before BOEM awards a lease, the lessee must maintain a $50,000 bond to ensure compliance with lease terms. The lessee may also hold an area wide bond of $300,000 for all tracts within a planning area (e.g., planning area 244).

If the lessee conducted lease exploration before receiving the lease from BOEM, its exploratory bond is sufficient. At 30 CFR 556.52, exploratory lease bonds are valued at $200,000 but the lessee is not required to provide such a bond if it provides an area wide bond for $1,000,000. Finally, prior to commencing lease development and production, 30 CFR 556.53 requires the lessee to provide a $500,000 lease development bond. Like the other bond requirements, the lease development bond is waived if the lessee maintains a $3,000,000 area wide bond. Subsequent regulations explain the process for providing bonds, including performance and management requirements for insurance companies.

The regulations at 30 CFR 250.1700 to 30 CFR 250.1754 establish detailed requirements for decommissioning wells. In general, as noted at 30 CFR 250.1703, the requirements include receiving proper decommissioning approval, permanently plugging all wells, removing platforms, decommissioning pipelines, clearing the seafloor of all obstructions and right-of-way operations, and completing all activities in a safe manner. Similar to the Alaska State requirements, the U.S. Government may request that some infrastructure remain in place when in the public interest. Subsequent regulations under 30 CFR 250 explain the conditions for requesting different decommissioning activities.

Rationale for bond amounts

The different amounts for bonds included in this memorandum demonstrate evolving state regulations for basing bonds. The 1962 lease agreements set minimum bond amounts at $1,000 per production platform or $5,000 per well. In the 1994 lease agreement, however, the minimum bond amount increases to $10,000, which is the amount required in 11 AAC 83.160 for lessees to provide before beginning development on a leased tract. Subsequent regulations appear to increase the bond amounts.

CSE asked ADNR for the assumptions involved with establishing and changing bond amounts. Such information was not readily available and would require significant investigation into the legislative and regulatory history of the State bonding requirements. However, the U.S. Government explanation for establishing its bond amounts may provide insight on the Alaska process. For example, the Mineral Leasing Act of 1920 as amended requires federal regulations to require bonds or surety (e.g., cashier's checks, certified checks) set for an adequate amount to ensure complete and timely reclamation (GAO 2010).

In *Oil and Gas Bonds: Bonding Requirements and BLM Expenditures to Reclaim Orphaned Wells*, the U.S. Government Accountability Office notes that Bureau of Land Management (BLM) bond amounts for oil and gas activities have not been updated since being set in the 1950s and 1960s. Thus, its $10,000 individual bond would increase to $59,360 in 2009 dollars. Regulators must determine if it is necessary to increase bond amounts. If so, they must further determine whether it is sufficient to simply adjust the current amount for inflation or whether a full rebasing is necessary.

Other approaches by the U.S. Government to establishing bond amounts seem better able to accommodate increasing DR&R costs. For example, BLM bond amounts for locatable minerals (e.g., gold, silver, copper) base the bond amount on the estimated costs for BLM to contract with a third-party for site reclamation. For salable materials including sand and gravel, BLM sets bond amounts based on sales contracts. By establishing requirements to set bond amounts on values that accommodate inflation or adjust according to sales, government agencies ensure that their DR&R costs are covered equitably.

Bonds and Other Surety Amounts Committed for DR&R in Cook Inlet

The total funding committed for DR&R activities associated with Cook Inlet fossil fuel infrastructure is impossible to estimate based on publicly available information. An unknown amount is carried as a liability on corporate asset sheets, and often placed in an independent trust account (Fineberg 2004). Several factors affect private sector companies' decisions about the amount of funding to hold in reserve; including court cases, settled bankruptcies, asset transfers, and shareholder preferences. Much of the information is treated as confidential corporate data. Moreover, DR&R liabilities are typically lumped together under an "asset retirement obligations" line item contained in annual reports filed with the Securities and Exchange Commission. The ambiguity makes disaggregation to a particular infrastructure component impossible even for analysts with access to corporate records (Rothe 2005).

What can be estimated – and what is most relevant for CSE's analysis – is what companies have committed through bonds required by laws and regulations. Should companies default on their DR&R obligations, these bonds would be the only source of committed funds on hand for cleanup and restoration activities. Unfortunately, identifying the public-bond financing for any one well, platform, or unit is also extremely difficult. While there are clear bonding requirements for DR&R associated with platforms, these requirements have numerous discretionary provisions that allow for adjustments in bond requirements based on perceived risk and other factors. Moreover, bond requirements are often reconsidered and adjusted as ownership changes or the context of bankruptcies or other legal proceedings.

Nonetheless, in order to estimate a rough estimate of the bonds committed for removal of Cook Inlet platforms, CSE reviewed lease agreements, published information, regulatory requirements, and conducted phone and e-mail interviews with ADNR staff.

Table 5 reports the results for three categories of bonds applicable to Cook Inlet platforms: (1) the acre-based bonds contained in lease agreements; (2) statewide bonds verified by ADNR staff[4], and (3) additional risk bonds reported by GAO (2002). As indicated by Table 5, for the 16 Cook Inlet offshore platforms, the total amount committed through these regulatory processes for DR&R is roughly $46 million. In addition to this amount, DOG staff identified additional bonding amounts secured in 2009 and 2013 as part of agreements with Hilcorp and Cook Inlet Energy. DOG staff indicated that these bonding amounts totaled an additional $140 million at most.[5]

Again, to reiterate: this estimate does not represent the total on hand for DR&R. Companies operating offshore platforms typically have already budgeted for DR&R and maintain those liabilities on their books. Rather, the values reported in Table 5 estimate what the State of Alaska should have on hand should companies default on their DR&R obligations.

Table 5: Estimated DR&R Funding for Cook Inlet Platforms Committed Through Bonding and Included in ADNR Records

Platform	Acre-based bond	Statewide bond	Risk bond*	DR&R Total**
Anna	$10,120	$500,000	-	$510,120
Baker	$10,212	$500,000	-	$510,212
Bruce	$10,120	$500,000	-	$510,120
Dillon	$6,400	$500,000	-	$506,400
Dolly Varden	$6,170	$500,000	-	$506,170
Granite Point	$10,178	$500,000	-	$510,178
Grayling	$10,232	$500,000	-	$510,232
King Salmon	$7,680	$500,000	-	$507,680
Monopod	$7,680	$500,000	-	$507,680
Osprey	$19,200	$500,000	$3,800,000	$4,319,200
Spark	$10,240	$500,000	-	$510,240
Spurr	$10,240	$500,000	-	$510,240
Steelhead	$7,680	$500,000	-	$507,680
Tyonek	$10,000	$500,000	-	$510,000
XTO A	$7,492	$500,000	$17,000,000	$17,507,492
XTO C	$10,240	$500,000	$17,000,000	$17,510,240
Totals:	$153,884	$8,000,000	$37,800,000	$45,953,884

** As reported by GAO (2009).*
*** For the three bond categories included. According to Alaska officials, there may be other bonds that are in place, but they could not be verified.*

Estimated actual DR&R costs needed to remove the infrastructure

Estimates for DR&R costs in Cook Inlet also carry uncertainty. Regulators and industry note three key sources of uncertainty including:

- Regulatory requirements. Although oil and gas companies clearly have obligations for DR&R and environmental remediation once fossil fuel infrastructure is not longer in use, the actual

[4] Personal communication with Corazon C Manaois and Kim Kruse, Alaska Division of Oil and Gas, 8/6 and 8/7, 2013. ADNR noted that, in addition to the $500,000 statewide bonds in place for each platform, all operators have additional bonds but the amounts were not included in ADNR records. CSE assumes that the per-acre bonds listed in Table 5 are included since they are specified in the lease agreements.
[5] Personal communication with Kevin Banks, Alaska Divisionof Oil and Gas, 9/4/13.

activities required are far less clear. For example, a full range of DR&R activities may include plugging and abandonment of wells. However, as noted by the GAO (2002), the State of Alaska's DR&R requirements "offer no specifics on what infrastructure must be removed or to what condition lands used for oil industry activities must be restored." Thus, estimating actual DR&R costs is only possible if regulatory requirements are made explicit with respect to the wide range of DR&R activities that apply.

- Infrastructure configuration. Actual DR&R costs for any specific platform, pipeline, or other infrastructure elements depends upon a variety of factors specific to the infrastructure in question. For example, according to a study commissioned by the former Minerals Management Service, platform decommissioning costs can vary widely due to factors such as location and type (complexity) of the facility, number of structures to be removed, weight associated with the structure, the number of wells and conductors, removal method, and transportation and disposal options (Proserv Offshore 2010).

- Location. The location of a particular infrastructure element is another major factor that influences costs. For example, a recent analysis of DR&R costs in the North Sea found a 14-fold difference between decommissioning costs in the southern North Sea (less expensive) versus locations in the northern and central portions (UK Oil and Gas 2012). The difference was explained in part by geographic factors such as ocean depth and weather.

Despite these factors, there are a number of information sources on which to draw to develop general estimates for at least two fossil infrastructure elements in Cook Inlet: offshore platforms and oil pipelines. These are the infrastructure elements for which DR&R requirements are most explicit and most regulated. For platforms, we incorporate estimates from four sources.

The first is a study of North Sea DR&R costs sponsored by UK Oil and Gas, an industry association (UK Oil and Gas 2012). This study – which is regularly updated – provides estimates for 32 platforms, 202 pipelines, and 295 wells scheduled to be decommissioned over the next 15 years. The study partitions the analysis into two North Sea regions – southern and northern/central. The study also differentiates between platform decommissioning costs, costs associated with plugging and abandonment of wells and operating costs during decommissioning. In terms of comparability, the southern North Sea may be more appropriate for Cook Inlet considering its relatively shallow depths, proximity to shore, and weather. In the southern North Sea, decommissioning costs were estimated at $28.51 million in 2013 dollars. Plugging and abandonment costs for platform wells were estimated at an additional $2.37 million per well. The study also estimates that plugging and abandonment costs represent 80 percent of total decommissioning costs. Thus, by knowing the number of wells associated with a particular platform, CSE can derive an additional estimate of decommissioning costs for the entire platform installation.

Incorporating operations costs is more complex. Operations costs are included in the UK Oil and Gas (2012) estimates because "the initial disconnection from producing hydrocarbons does not significantly reduce the numbers of personnel and significant work is required to prepare the installations for decommissioning, such as cleaning, maintenance and activities carried out to ensure asset integrity is maintained before and during decommissioning." However, if DR&R activities commence relatively soon after production ceases, these costs are minimized. Also, it is unclear whether operations costs ought to be tallied under DR&R or just recorded as-after-the-fact production costs. Because we have no basis for predicting the length of time between production cessation and DR&R commencement for Cook Inlet platforms or how companies are treating these costs, we exclude them for now.

The second is a study of decommissioning 23 offshore platforms in California, prepared by Proserv Offshore for the Minerals Management Service, now BOEM (Proserv Offshore 2010). The analysis provides estimates ranging from $12 million to $149 million per platform – or an average of $59.29 million per platform in 2013 dollars. Thirteen cost categories were considered (Appendix 2). Key factors driving the variance between platform costs were size, weight, and water depth.

The third source is an estimate for the Spurr platform in Cook Inlet. A dispute between Marathon Oil Company and Pacific Energy Resources (the former operator) led to litigation over DR&R liability.[6] As part of that litigation, expected DR&R costs were made public. Estimates range from $23 million to $38 million in 2013 dollars. The fourth is a cost estimate for XTO Platforms A and C, the subject of a 1998 abandonment agreement with the State. The agreement estimated DR&R costs of $15.5 million per platform for plugging and abandonment of all wells, removal of all structures, and buildings on the platform, and removal of the platform and associated pipelines (Rothe 2005). This is $22.2 million in current dollars.

For oil pipelines, CSE incorporated two estimates referenced in Fineberg (2004) and based upon Alaska Public Utility Commission proceedings. The first is for the Cook Inlet Pipeline. DR&R costs were estimated to be $17.9 million in 1982 or $43.3 million in 2013 dollars. The second estimate is for the Kenai pipeline, estimated at $5.66 million in 2013 dollars. Respectively, and based upon lengths reported in Table 2, these estimates translate into costs of $1.03 million and $0.29 million per mile.[7]

Table 6 summarizes these cost figures for both platforms and pipelines and what they imply for unit costs. Applying the minimum and maximum values from these data, CSE derived estimates of minimum (i.e., excluding operations costs) DR&R costs for all 16 Cook Inlet platforms and 160 miles of pipelines described in Tables 1 and 2. For platforms, CSE estimates range from $355.20 million to $948.64 million, a mean value of $651.92 million. For pipelines, CSE estimates range from $47.17 million to $164.95 million, with a mean of $106.06 million. Combined, the estimates imply a minimum DR&R liability for platforms and oil pipelines alone in Cook Inlet to range between $402.37 million and $1.11 billion. Comparing these cost figures to figures from Table 5 and additional bonding information supplied by DOG staff suggests that surety bonds committed to support Alaska DR&R activities represent no more than 25 to 50 percent of funds required for DR&R activities should companies default on their obligations.

Table 6: Estimates of DR&R Costs for Cook Inlet Platforms and Pipelines

Infrastructure element	Unit cost assumption ($2013 millions)	Total costs ($2013 millions)	Source
Platforms	$22.20 per platform	$355.20	Rothe (2005); GAO (2002)
Platforms	$22.85 per platform	$365.60	Law360 (2010)
Platforms	$28.51 per platform	$456.16	UK Oil and Gas (2012)
Platforms	$38.09 per platform	$609.44	Law360 (2010)
Platforms	$45.33 per platform	$725.28	UK Oil and Gas (2012)[8]
Platforms	$59.29 per platform	$948.64	Proserv Offshore 2010
Pipelines	$0.29 per mile	$47.17	Kenai pipeline in Fineberg (2004)
Pipelines	$1.03 per mile	$164.95	Cook Inlet pipeline in Fineberg (2004)

[6] See Law360 at: http://www.law360.com/articles/210856/marathon-pacific-energy-pitch-ch-11-platform-deal.
[7] For both, we excluded shorter facility pipelines that bear the same project name.
[8] Based on wells per platform reported in Table 1 and a plugging and abandonment cost of $2.37 million per well inflated by 20 percent as per UK Oil and Gas (2012) assumptions.

Conclusions

Despite a resurgence of investment in oil and gas production in Cook Inlet and new, more optimistic reserve estimates, the disposition of ageing and obsolete fossil fuel infrastructure remains a major public concern. Much of this infrastructure was installed during the 1960s and is now far beyond its expected design life. Once operations cease at ageing oil platforms, pipelines, and onshore processing facilities, companies will need to commence DR&R activities which require removal of all infrastructure and restoration of marine and coastal environments.

While companies are presumed to have retained financial resources to complete DR&R tasks, the uncertainty inherent to profits, losses, and ownership changes affects their assets. If companies were to default on their responsibility, presumably the State of Alaska would bear the costs. But bonds required by the State represent only a fraction of the resources needed. This report suggests that likely bond values represent 25-50% of the likely $402 million to $1.11 billion needed to safely remove platforms and oil pipelines and complete ecological restoration activities. Gas pipelines and other infrastructure subject to DR&R requirements would put this cost far higher and the gap much greater. The magnitude of the gap suggests that bond requirements be reformed and related to actual DR&R costs rather than the nominal fees now set in place by Alaska statutes, rules, and regulations.

As a result, this report makes the following preliminary observations and recommendations:

- Bonding and related surety obligations for oil and gas infrastructure need enhanced clarity and predictability to best serve the interests of industry, government and Alaskans alike;

- Currently, it is difficult and at times impossible to understand the amounts obligated by oil and gas companies for DRR operations; as a result, new DNR rules should promote transparency to allow members of the public, agency personnel and stockholders to better understand DRR liabilities;

- Regardless of a corporation's financial fitness, the recent financial crisis has shown that there is no such thing as "too big to fail." As a result, any new bonding or surety strategies must ensure all companies with DRR obligations, regardless of their financial wherewithal, set aside the resources needed to meet their DRR responsibilities.

- Bonding requirements should not be based on a schedule of nominal fees, but the actual expected costs of DR&R for each facility, pipeline, platform, or other infrastructure element.

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Alaska Administrative Code Title 11 Chapter 83:
http://www.legis.state.ak.us/basis/folioproxy.asp?url=http://wwwjnu01.legis.state.ak.us/cgi-bin/folioisa.dll/aac/query=[JUMP:%27Title11Chap83%27]/doc/{@1}?firsthit

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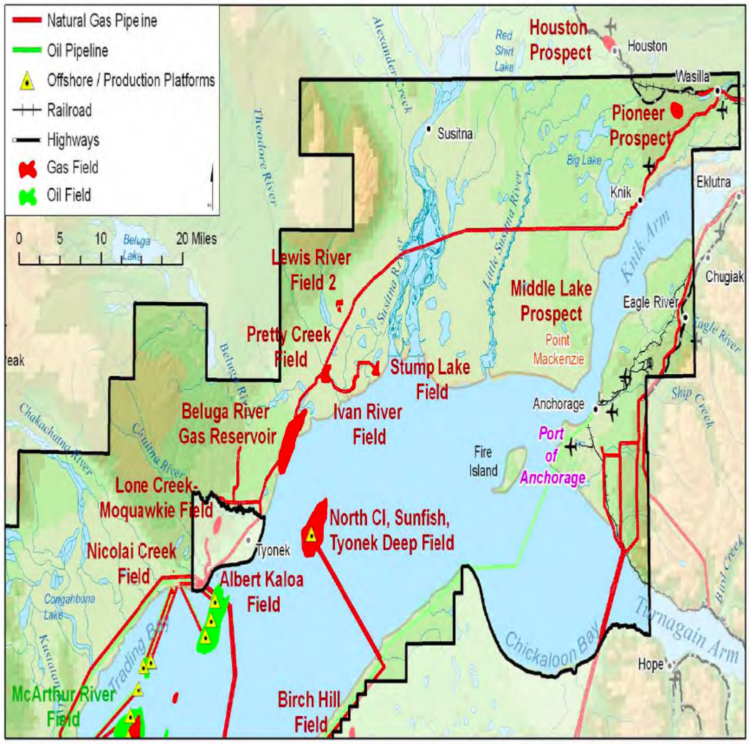
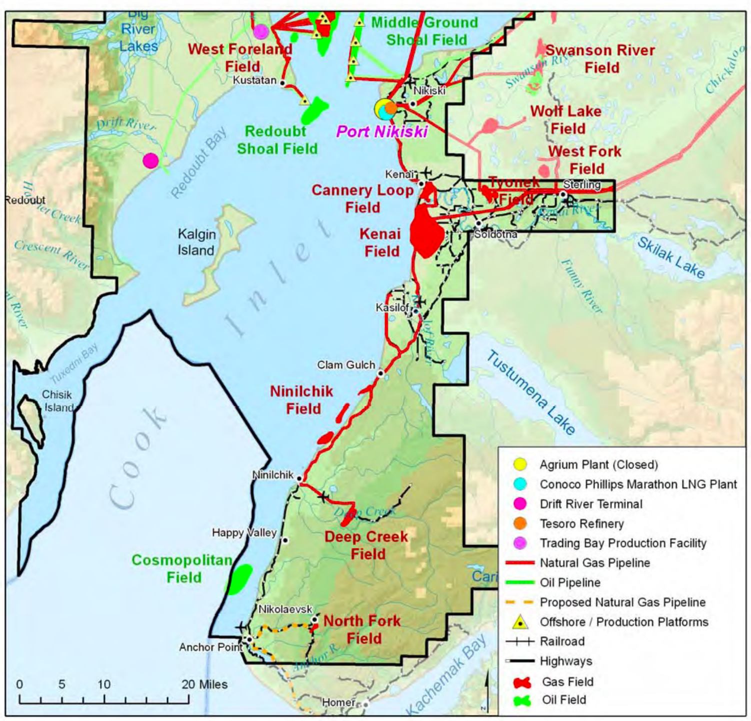
Appendix 1: Cook Inlet Fossil Fuel Infrastructure (DOG 2009)





Appendix 2: Platform Decommissioning Costs (Proserv Offshore 2010)