

MATERIAL SAFETY DATA SHEET

CRUDE OIL

MSDS No.
RS296

Version: 5

Rev. Date
05/13/2002

IMPORTANT: Read this MSDS before handling and disposing of this product and pass this information on to employees, customers, and users of this product.

1. PRODUCT and COMPANY IDENTIFICATION

Material Identity	Crude Oil		
Trade Name(s)	Oriente, Cano Limon, Line 63, Shell-Ventura, SJV Light, Rainbow, West Texas Inter-Cushing, Peace River-Canadian, Federated Crude-Canadian, Pembina Crude-Canadian, Forcados, Cabinda, Basrah Light, Basrah, Arab Medium, Elang Crude, Girassol		
Other Name(s)	Earth Oil, Petroleum Oil, Rock Oil, Zafiro		
Chemical Description	This material is a C1 to C50 hydrocarbon liquid which contains approximately .9 to 2.8 wt% sulfur compounds		
Manufacturer's Address	BP West Coast Products LLC Carson Business Unit 1801 E. Sepulveda Boulevard Carson, California 90749-6210	BP West Coast Products LLC Cherry Point Business Unit 4519 Grandview Road Blaine, Washington 98230	
Telephone Numbers	Emergency Health Information:	1 (800) 447-8735	
	Emergency Spill Information:	1 (800) 424-9300 CHEMTREC (USA)	
	Other Product Information:	1 (866) 4BP-MSDS (866-427-6737 Toll Free - North America) email: bpcares@bp.com	

2. COMPONENTS and EXPOSURE LIMITS

<u>Component</u> ¹	<u>CAS No.</u>	<u>% Composition By Volume</u> ²		<u>ACGIH TLV</u>	<u>Exposure Limits OSHA</u> ³		
					<u>PEL</u>	<u>Units</u>	<u>Type</u>
CRUDE OIL, PETROLEUM	8002-05-9	EQ	100	N/AP	N/AP		
which contains:							
BUTANE	106-97-8	AP	0.8 to 1	800	800	pm	TWA
HEXANE (N-HEXANE)	110-54-3	AP	0.3 to 1	50 skin	50	ppm	TWA
ISOPENTANE	78-78-4	AP	0.3 to 1.5	N/AP 600	750 600	ppm ppm	STEL TWA
PENTANE	109-66-0	AP	1.5 to 2.5	N/AP 600	750 600	ppm ppm	STEL TWA
Other applicable exposure guidelines:							
COAL TAR PITCH VOLATILES, AS BENZENE SOLUBLES ⁽⁴⁾	65996-93-2			0.2	0.2	mg/m3	TWA
OIL MIST, MINERAL	8012-95-1			10 5	N/AP 5	mg/m3 mg/m3	STEL TWA
STODDARD SOLVENT	8052-41-3			100	100	ppm	TWA

Stoddard Solvent exposure limits are listed as an exposure guideline for hydrocarbon vapors that may be similar to those derived from crude oil.

Since specific exposure standards or control limits have not been established for this material, the exposure limits shown here are suggested as minimum control guidelines.

¹ Carcinogen displayed after Component Name. Listed by ⁽¹⁾ NTP, ⁽²⁾ IARC, ⁽³⁾ OSHA, ⁽⁴⁾ Other

² See Abbreviations on last page

³ The OSHA exposure limits were changed in 1993 due to a federal court ruling. ARCO has chosen to list the 1989 OSHA exposure limits in this document as they are generally more stringent and therefore more protective than the current exposure limits. (Refer to 29 CFR 1910.1000).

3. HAZARD IDENTIFICATION

IMMEDIATE HAZARDS

DANGER

HIGHLY FLAMMABLE! OSHA/NFPA Class 1B flammable liquid. KEEP AWAY FROM HEAT, SPARKS, AND OPEN FLAME! CONTAINS PETROLEUM DISTILLATES! Avoid breathing vapors or mists. Use only with adequate ventilation. If swallowed, do not induce vomiting since aspiration into the lungs may cause chemical pneumonia. Obtain prompt medical attention.

May cause irritation or more serious skin disorders! May be harmful if inhaled! May cause irritation of the nose, throat, and lungs, headache, dizziness, drowsiness, loss of coordination, fatigue, nausea and labored breathing. May cause irregular heartbeats. Avoid prolonged or repeated liquid, mist, and vapor contact with eyes, skin, and respiratory tract.

Wash hands thoroughly after handling.

Sulfur compounds in this material may decompose to release hydrogen sulfide gas which may accumulate to potentially lethal concentrations in enclosed air spaces. Vapor concentrations of hydrogen sulfide above 50 ppm, or prolonged exposure at lower concentrations, may saturate human odor perceptions so that the smell of gas may not be apparent. **DO NOT DEPEND ON THE SENSE OF SMELL TO DETECT HYDROGEN SULFIDE!**

Long-term tests show that similar crude oils have produced skin tumors on laboratory animals.

Crude oils contain some polycyclic aromatic hydrocarbons which have been shown to be carcinogenic after prolonged or repeated skin contact in laboratory animals.

Routes of Exposure

Signs and Symptoms

Inhalation (Primary)

Vapors or mists from this material, at concentrations greater than the recommended exposure limits in Section 2, can cause irritation of the nose, throat, and lungs, headache, dizziness, drowsiness, loss of coordination, fatigue, nausea and labored breathing. Airborne concentrations above the recommended exposure limits are not anticipated during normal workplace activities due to the slow evaporation of this material at ambient temperatures.

Exposure to moderate airborne concentrations of hydrogen sulfide (less than 50 ppm) can result in irritation of the eyes, nose and throat, headache, dizziness, shortness of breath, nausea and nervousness. Exposure to hydrogen sulfide vapor above 200 ppm may cause irritation of mucous membranes, inflammation of the lungs, accumulation of fluid in the lungs, irregular heartbeats, unconsciousness with convulsions or impaired breathing with suffocation. Exposure to higher concentrations of hydrogen sulfide vapor (above 500 ppm) may cause rapid death.

Eye Contact

May cause slight eye irritation.

Skin Contact

Moderate skin irritation may occur upon short-term exposure.

Exposure to sunlight may increase the degree of skin irritation.

Absorption through the skin may occur and produce toxic effects (see Summary of Chronic Hazards).

Ingestion

May cause irritation of the mouth, throat and gastrointestinal tract leading to nausea, vomiting, diarrhea, and restlessness. May cause headache, dizziness, drowsiness, loss of coordination, fatigue, nausea and labored breathing.

ASPIRATION HAZARD: Aspiration into the lungs may cause chemical pneumonia. This material can enter the lungs during swallowing or vomiting and may cause lung inflammation and damage which in severe cases may be fatal.

Summary of Chronic Hazards and Special Health Effects

Personnel with preexisting central nervous system (CNS) disease, skin disorders, or chronic respiratory diseases should be evaluated by an appropriate health professional before exposure to this material.

Prolonged/repeated skin exposure, inhalation or ingestion of this material may result in adverse dermal or systemic effects. Avoid prolonged or repeated exposure. May be harmful if absorbed through the skin. Prolonged or repeated contact may create cancer risk, organ damage, and adversely affect reproduction, fetal development and fetal survival. Avoid all skin contact.

Neurotoxic effects have been associated with n-hexane, a component of this material. Avoid prolonged or repeated exposure.

See Section 11 for Additional Toxicological Information.

4. EMERGENCY and FIRST AID

Inhalation	Immediately remove personnel to area of fresh air. For respiratory distress, give oxygen, rescue breathing, or administer CPR (cardiopulmonary resuscitation) if necessary. Obtain prompt medical attention.
Eye Contact	Flush eyes with clean, low-pressure water for at least 15 minutes, occasionally lifting the eyelids. If pain or redness persists after flushing, obtain medical attention.
Skin Contact	Immediately remove contaminated clothing. Wash affected skin thoroughly with soap and water. If irritation persists, obtain medical attention.
Ingestion	Do not induce vomiting since aspiration into the lungs may cause lipid pneumonia. Obtain prompt medical attention.

Emergency Medical Treatment Procedures

See above procedures. Personnel with pre-existing central nervous system disease, skin disorders, chronic respiratory diseases, or impaired liver or kidney function should avoid exposure to this product.

5. FIRE and EXPLOSION

Flash Point (Method)* Based on NFPA Petroleum, Crude	AP 20°F to 90°F	NFPA Hazard Rating: Health: 2 = Moderate Fire: 3 = High Reactivity: 0 = Insignificant Special:
Autoignition Temperature (Method)*	N/DA	
Flammable Limits (% Vol. in Air*)	Lower AP 1 + Upper AP 8 +	
	* Based on NFPA 325	

* At Normal Atmospheric Temperature and Pressure

Fire and Explosion Hazards

HIGHLY FLAMMABLE! This material releases flammable vapors at or below ambient temperatures. When mixed with air in certain proportions and exposed to an ignition source, these vapors can burn in the open or explode in confined spaces.

Flammable vapors may travel long distances along the ground before reaching a point of ignition and flashing back.

Open top tanks involved in a fire have a potential for "boil-over" if water or water-in-oil emulsion is at the bottom of the tank. Boil-over may result in a large expulsion of burning oil from the tank, greatly increasing the fire area.

Extinguishing Media

Foam, Dry chemical, Carbon dioxide (CO₂)

Water and water fog can cool the fire but may not extinguish the fire.

Special Firefighting Procedures

For fires involving this material, do not enter any enclosed or confined fire space without proper protective equipment. This may include self-contained breathing apparatus to protect against the hazardous effects of combustion products and oxygen deficiencies. Cool tanks and containers exposed to fire with water. If firefighters cannot work upwind to the fire, respiratory protective equipment must be worn unless and until atmospheric monitoring indicates that such protection is not required. Improper use of water and extinguishing media containing water may cause frothing which can spread the fire over a larger area. Water fog or spray are of value for cooling tank shells and surfaces exposed to fire, but may not achieve extinguishment.

6. ACCIDENTAL RELEASE MEASURES

Precautions if Material is Spilled or Released Contain spill, evacuate non-essential personnel, and safely stop flow. On hard surfaces, spilled material may create a slipping hazard. Equip cleanup crews with proper protective equipment (as specified in Section 8) and advise of hazards. Clean up by recovering as much spilled or contaminated materials as possible and placing into closed containers. Consult with an environmental professional for the federal, state and local cleanup and reporting requirements for spills and releases.

7. HANDLING and STORAGE

Handling, Storage and Decontamination Procedures Store and transport in accordance with all applicable laws. KEEP AWAY FROM HEAT, SPARKS, AND OPEN FLAME! KEEP CONTAINERS CLOSED, PLAINLY LABELED AND OUT OF CLOSED VEHICLES! Containers should be able to withstand pressures expected from warming or cooling in storage. Ground all drums and transfer vessels when handling. Store in cool (80°F or below), well-ventilated location. All electrical equipment in storage and/or handling areas should be installed in accordance with applicable requirements of the National Electrical Code (NEC).

KEEP OUT OF REACH OF CHILDREN!

Empty containers retain some liquid and vapor residues, and hazard precautions must be observed when handling empty containers.

For determining National Electrical Code (NEC) Hazardous (Classified) location requirements for electrical installations, consider this material Class 1, Group D.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Engineering Controls Where possible, use adequate ventilation to keep vapor and mist concentrations of this material below the Occupational Exposure Limits shown in Section 2. Electrical equipment should comply with National Electrical Code (NEC) standards (see Section 7).

Respiratory Where there is potential for exposure to hydrogen sulfide gas in excess of the permissible exposure limit, a NIOSH/MSHA-approved supplied-air respirator operated in positive pressure mode should be worn.

If hydrogen sulfide gas is not present in excess of permissible exposure limits, a NIOSH/MSHA-approved air-purifying respirator with an organic vapor cartridge may be permissible under certain circumstances where airborne concentrations of hydrocarbon vapor may exceed the exposure limits in Section 2. Where work conditions may generate airborne mists of the material, also use a high-efficiency particulate pre-filter. Consult a health and safety professional for guidance in respirator selection. Respirator use should comply with OSHA 29 CFR 910.134.

CAUTION: The protection provided by air-purifying respirators is limited. Use a positive pressure air-supplied respirator if there is any potential for an uncontrolled release, if exposure levels are not known, or if concentrations exceed the protection limits of the air-purifying respirator.

Eyes Eye protection should be worn. If there is potential for splashing or spraying, chemical protective goggles and/or a face shield should be worn. If contact lenses are worn, consult an eye specialist or a safety professional for additional precautions. Suitable eye wash water should be available in case of eye contact with this material.

Skin Avoid all skin contact with this material. If conditions of use present any potential for skin contact, clean and impervious clothing such as gloves, apron, boots, and facial protection should be worn. Neoprene, Nitrile, Butyl Rubber or Viton glove material is recommended. When working around equipment or processes which may create the potential for skin contact, full body coverage should be worn, which consist of impervious boots and oil-resistant coated Tyvek suit or other impervious jacket and pants.

Non-impervious clothing which accidentally becomes contaminated with this material should be removed promptly and not reworn until the clothing is washed thoroughly and the contamination is effectively removed. Discard soaked leather goods.

Other Hygienic and Work Practices

Use good personal hygiene practices. If skin contact should occur, material should be removed from the skin with a waterless hand cleaner, and the affected area should then be washed with a mild soap and water. Wash hands and other exposed areas thoroughly before eating, drinking, smoking or using toilet facilities.

9. PHYSICAL and CHEMICAL PROPERTIES

Boiling Point:	AP -54°F to 1100°F
Viscosity Units, Temp. (Method):	N/DA
Dry Point:	N/AP
Freezing Point:	N/DA
Vapor Pressure, Temp. (Method):	AP 1 to 2 at 100°F (REID-PSIA)
Volatile Characteristics:	Appreciable
Specific Gravity (H₂O = 1 @ 39.2°F):	AP 0.88
Vapor Sp. Gr. (Air = 1.0 @ 60°F - 90°F):	N/DA
Solubility in Water:	Negligible
PH:	N/AP
Appearance and Odor:	Thick light yellow to dark black colored liquid. Petroleum hydrocarbon odor.
Other Physical and Chemical Properties:	Total sulfur = approx. 1.1% - 2.8% Hydrogen sulfide content is less than 5 ppm dissolved in liquid Vanadium = approx. 210 ppm

10. STABILITY and REACTIVITY

Stability	Stable
Hazardous Polymerization	Not expected to occur.
Other Chemical Reactivity	N/AP

Conditions to Avoid	Heat, sparks, and open flame.
Materials to Avoid	Strong acids, alkalis, and oxidizers such as liquid chlorine and oxygen.
Hazardous or Decomposition Products	Burning or excessive heating may produce carbon monoxide and other harmful gases or vapors including oxides of sulfur and nitrogen.

11. TOXICOLOGICAL INFORMATION

Toxicological Information The information found in this section is written for medical, toxicology, occupational health and safety professionals. This section provides technical information on the toxicity testing of this or similar materials or its components. If clarification of the technical content is needed, consult a professional in the areas of expertise listed above.

Prolonged/Repeated Exposures IARC has determined there is "limited evidence for the carcinogenicity in experimental animals of crude oil" and "inadequate evidence for the carcinogenicity in humans of crude oil." IARC concludes that "crude oil is not classifiable as to its carcinogenicity to humans (Group 3)."

Crude oil administered orally to pregnant rats during gestation produced increased number of resorptions and decrease in fetal weight and length.

Exposure to N-hexane at concentrations considerably higher than the current permissible exposure limit has reportedly been associated with peripheral neuropathy.

12. ECOLOGICAL INFORMATION

Not Available

13. DISPOSAL CONSIDERATIONS

Waste Disposal Methods Maximize recovery for reuse or recycling. Consult environmental professional to determine if state or federal regulations would classify spilled or contaminated materials as a hazardous waste. Use only approved transporters, recyclers, treatment, storage or disposal facilities. Comply with all federal, state and local laws pertaining to waste management.

14. TRANSPORT INFORMATION

UN Proper Shipping Name	Petroleum crude oil
UN Hazard Class	3
UN Number	UN1267
UN Packing Group	PGI

15. REGULATORY INFORMATION

SUPERFUND AMENDMENTS AND REAUTHORIZATION ACT OF 1986 (SARA), TITLE III

Section 311/312 Hazard Categories:

Immediate (acute) health hazard
 Delayed (chronic) health hazard
 Fire hazard

No chemicals in this product exceed the threshold reporting level established by SARA Title III, Section 313 and 40 CFR 372.

TOXIC SUBSTANCES CONTROL ACT (TSCA)

All components of this product are listed on the TSCA Inventory.

COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION AND LIABILITY ACT (CERCLA)

This material is covered by CERCLA's PETROLEUM EXEMPTION.

(Refer to 40 CFR 307.14)

CALIFORNIA SAFE DRINKING WATER AND TOXIC ENFORCEMENT ACT OF 1986 - PROPOSITION 65

PROP 65 WARNING LABEL:

Chemicals known to the State to cause cancer, birth defects, or other reproductive harm are found in gasoline, crude oil, and many other petroleum products and their vapors, or result from their use. Read and follow label directions and use care when handling or using all petroleum products.

WARNING:

This product contains the following chemical(s) listed by the state of California as known to cause cancer or birth defects or other reproductive harm.

MINERAL OILS, UNTREATED ^(C)

Other Prop 65 chemicals will result under certain conditions from the use of this material. For example, burning fuels produces combustion products including carbon monoxide, a Prop 65 reproductive toxin.

^(C) = Carcinogen

16. OTHER INFORMATION

**General
Comments**

The information and conclusions herein reflect normal operating conditions and may be from sources other than direct test data on the mixture itself.

Abbreviations:	EQ = Equal	AP = Approximately	N/P = No Applicable Information Found
	LT = Less Than	UK = Unknown	N/AP = Not Applicable
	GT = Greater Than	TR = Trace	N/DA = No Data Available

Prepared by: Product Stewardship

Disclaimer of Liability

The information in this MSDS was obtained from sources which we believe are reliable. **HOWEVER, THE INFORMATION IS PROVIDED WITHOUT ANY WARRANTY, EXPRESS OR IMPLIED, REGARDING ITS CORRECTNESS.**

The conditions or methods of handling, storage, use and disposal of the product are beyond our control and may be beyond our knowledge. **FOR THIS AND OTHER REASONS, WE DO NOT ASSUME RESPONSIBILITY AND EXPRESSLY DISCLAIM LIABILITY FOR LOSS DAMAGE OR EXPENSE ARISING OUT OF OR IN ANY WAY CONNECTED WITH THE HANDLING, STORAGE, USE OR DISPOSAL OF THE PRODUCT.**

This MSDS was prepared and is to be used only for this product. If the product is used as a component in another product, this MSDS information may not be applicable.

SCREENING-LEVEL HAZARD CHARACTERIZATION

Crude Oil Category

SPONSORED CHEMICAL Crude Oil (CASRN 8002-05-9)

The High Production Volume (HPV) Challenge Program¹ was conceived as a voluntary initiative aimed at developing and making publicly available screening-level health and environmental effects information on chemicals manufactured in or imported into the United States in quantities greater than one million pounds per year. In the Challenge Program, producers and importers of HPV chemicals voluntarily sponsored chemicals; sponsorship entailed the identification and initial assessment of the adequacy of existing toxicity data/information, conducting new testing if adequate data did not exist, and making both new and existing data and information available to the public. Each complete data submission contains data on 18 internationally agreed to “SIDS” (Screening Information Data Set^{1,2}) endpoints that are screening-level indicators of potential hazards (toxicity) for humans or the environment.

The Environmental Protection Agency’s Office of Pollution Prevention and Toxics (OPPT) is evaluating the data submitted in the HPV Challenge Program on approximately 1400 sponsored chemicals by developing hazard characterizations (HCs). These HCs consist of an evaluation of the quality and completeness of the data set provided in the Challenge Program submissions. They are not intended to be definitive statements regarding the possibility of unreasonable risk of injury to health or the environment.

The evaluation is performed according to established EPA guidance^{2,3} and is based primarily on hazard data provided by sponsors; however, in preparing the hazard characterization, EPA considered its own comments and public comments on the original submission as well as the sponsor’s responses to comments and revisions made to the submission. In order to determine whether any new hazard information was developed since the time of the HPV submission, a search of the following databases was made from one year prior to the date of the HPV Challenge submission to the present: (ChemID to locate available data sources including Medline/PubMed, Toxline, HSDB, IRIS, NTP, ATSDR, IARC, EXTOXNET, EPA SRS, etc.), STN/CAS online databases (Registry file for locators, ChemAbs for toxicology data, RTECS, Merck, etc.) and Science Direct. OPPT’s focus on these specific sources is based on their being of high quality, highly relevant to hazard characterization, and publicly available.

OPPT does not develop HCs for those HPV chemicals which have already been assessed internationally through the HPV program of the Organization for Economic Cooperation and Development (OECD) and for which Screening Initial Data Set (SIDS) Initial Assessment Reports (SIAR) and SIDS Initial Assessment Profiles (SIAP) are available. These documents are presented in an international forum that involves review and endorsement by governmental

¹ U.S. EPA. High Production Volume (HPV) Challenge Program; <http://www.epa.gov/chemrtk/index.htm>.

² U.S. EPA. HPV Challenge Program – Information Sources; <http://www.epa.gov/chemrtk/pubs/general/guidocs.htm>.

³ U.S. EPA. Risk Assessment Guidelines; <http://cfpub.epa.gov/ncea/raf/rafguid.cfm>.

authorities around the world. OPPT is an active participant in these meetings and accepts these documents as reliable screening-level hazard assessments.

These hazard characterizations are technical documents intended to inform subsequent decisions and actions by OPPT. Accordingly, the documents are not written with the goal of informing the general public. However, they do provide a vehicle for public access to a concise assessment of the raw technical data on HPV chemicals and provide information previously not readily available to the public.

Chemical Abstract Service Registry Number (CASRN)	8002-05-9
Chemical Abstract Index Name	Crude Petroleum
Structural Formula	See Appendix
Summary	
<p>Petroleum (crude oil) is a complex mixture of paraffinic, naphthenic and aromatic hydrocarbons ranging in carbon number from C1 to >C60. Petroleum typically also contains smaller amounts of heteroatom compounds, metals (either complexed with porphyrins or as salts of carboxylic acids) and hydrogen sulfide. Petroleum is not a uniform substance since its physical and chemical properties vary from oilfield to oilfield and can even vary within wells at the same oilfield. At one extreme, it is a light, mobile, straw-colored liquid. At the other extreme, it is a highly viscous, semi-solid, black substance. The lower molecular weight components of petroleum possess moderate to high water solubility while higher molecular weight fractions tend to form emulsions in water. The lower molecular weight components of petroleum have high vapor pressure while higher molecular weight fractions tend to possess negligible to low vapor pressure. The lighter weight aliphatic and aromatic components of petroleum will have high mobility in soils while the heavier molecular weight constituents will possess low mobility. Volatilization is expected to be moderate to high for most constituents of petroleum. The rate of hydrolysis is negligible since paraffins, naphthenes and the aromatic hydrocarbons contained in petroleum do not possess functional groups that hydrolyze under environmental conditions. The rate of atmospheric photooxidation is expected to be slow to rapid for most components of petroleum. The components of petroleum are expected to possess low (P1) to high (P3) persistence and low (B1) to high (B3) bioaccumulation potential.</p> <p>The acute toxicity of CASRN 8002-05-9 is low in rats and mice by the oral route, low to moderate in rats and moderate in mice by the inhalation route and low in rabbits by the dermal route. A 28-day dermal repeated-dose toxicity study in rats showed reduced body weight gain in males at 2500 mg/kg-day and no effects in females at 2500 mg/kg-day (highest dose tested). The NOAEL is 250 mg/kg-day in males and 2500 mg/kg-day in females. A 90-day dermal repeated-dose toxicity study in rats showed hypertrophy and hyperplasia of follicular thyroid epithelium in males and females at 30 mg/kg-day; the NOAEL was not established. In a second 90-day dermal repeated-dose toxicity study in rats, both males and females showed hypertrophy and hyperplasia of follicular thyroid epithelium and males showed increased bone marrow cellularity at 30 mg/kg-day; the NOAEL was not established. No specific reproductive toxicity studies are available. In the dermal repeated-dose toxicity study, no effects on the reproductive organs were observed in male rats treated with 500 mg/kg-day (only dose tested). In a prenatal developmental toxicity study in rats administered CASRN 8002-05-9 via gavage, reduced maternal body weight was observed at 887 mg/kg-day; the NOAEL for maternal toxicity was not established. Signs of developmental toxicity consisted of reduced fetal weight, reduced fetal</p>	

crown-rump length, increased numbers of resorptions and the number of dead fetuses and decreased number of live fetuses at 887 mg/kg-day; the NOAEL for developmental toxicity was not established. In a prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 500 mg/kg-day; the NOAEL for maternal toxicity is 125 mg/kg-day. Signs of developmental toxicity consisted of increased number of resorptions, decreased litter size, decreased fetal weight, incomplete ossification of nasal bones and caudal centra and an increased incidence of pup mortality during lactation at 500 mg/kg-day; the NOAEL for developmental toxicity is 125 mg/kg-day. In another prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 500 mg/kg-day; the NOAEL for maternal toxicity is 125 mg/kg-day. Incomplete ossification of fetal nasal bones was observed in pups at 125 mg/kg-day; the NOAEL for developmental toxicity was not established. In a third prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 1000 mg/kg-day; the NOAEL for maternal toxicity is 500 mg/kg-day. Signs of developmental toxicity consisted of reduced pup body weight and body weight gain at 1000 mg/kg-day; the NOAEL for developmental toxicity is 500 mg/kg-day. CASRN 8002-05-9 was mutagenic in bacteria *in vitro* but did not show evidence of chromosomal aberrations in mammalian cells *in vitro*. CASRN 8002-05-9 did induce chromosomal aberrations in mice *in vivo*. CASRN 8002-05-9 is irritating to rabbit skin and eyes and did not induce sensitization in guinea pigs. CASRN 8002-05-9 is carcinogenic to mice via dermal exposure.

Reproductive toxicity was identified as a data gap under the HPV Challenge Program.

The 96-h LC₅₀ of CASRN 8002-05-9 for fish ranges from 0.73 to 42 mg/L. The 48-h EC₅₀ of CASRN 8002-05-9 for aquatic invertebrates ranges from 0.61 to 28 mg/L. The 21-d chronic toxicity to aquatic invertebrates ranges from 0.5 to 6 mg/L.

The toxicity to aquatic plants endpoint was identified as a data gap under the HPV Challenge Program.

The sponsor, American Petroleum Institute (API) Petroleum HPV Testing Group, submitted a Test Plan and Robust Summaries to EPA for Crude Oil (CASRN 8002-05-9) on November 25, 2003. EPA posted the submission on the ChemRTK HPV Challenge website on December 19, 2003 (<http://www.epa.gov/oppt/chemrtk/pubs/summaries/crdoilct/c14858tc.htm>). EPA comments on the original submission were posted to the website on May 20, 2004. Public comments were also received and posted to the website. The sponsor submitted updated/revised documents on January 14, 2011, which were posted to the website on February 3, 2011.

Category Justification

The crude oil category contains only CASRN 8002-05-9 and represents all conventional crude oils, including synthetic crude oils derived from tar sands, regardless of source or hydrocarbon distribution. Crude oil is a Class 2⁴ substance which may contain varying concentrations of paraffinic, naphthenic and aromatic hydrocarbons with carbon numbers ranging from C1 to C60+. The proportions of paraffinic, naphthenic, and aromatic hydrocarbons, as well as other components, differ among geographic regions. Crude oils also contain varying amounts of nitrogen, oxygen, and sulfur compounds, organometallic complexes (notably of sulfur and vanadium), dissolved gases such as hydrogen sulfide, heteroatoms (e.g., nitrogen- and oxygen-containing hydrocarbon analogs), and asphaltenes. The heterogeneity in the composition of the different crude oils, could produce different profiles of toxic effects in mammals and aquatic organisms. EPA agrees, however, that grouping these mixtures into a single category is appropriate based on the general composition profile and physicochemical properties. EPA recognizes that due to the nature of crude oil and the compositional variation that can occur with region of origin and even location within a geographic formation, the specific crude oils represented in the studies presented in this hazard characterization may not be representative of the hazard observed following exposure to different crude oils which have not been tested.

1. Chemical Identity

1.1 Identification and Purity

The following description is taken from the 2003 Test Plan and Robust Summary. Crude oil is a complex combination of hydrocarbons consisting predominantly of aliphatic, alicyclic and aromatic hydrocarbons covering the carbon number range from C1 to C60+. It also contains sulfur, oxygen and nitrogen compounds, organometallic complexes notably of sulfur and vanadium, and dissolved gases such as hydrogen sulfide. In appearance, crude oils range from thin, light colored oils consisting mainly of gasoline-quality stock to heavy, thick tar-like

⁴ Class 2 denotes a chemical that occurs as a complex mixture of different individual substances rather than existing as a single chemical species with a well-defined molecular structure (e.g., a paraffin wax). Class 2 compounds also include unknown or variable composition complex reaction products, biological materials (UVCB). UVCB substances can for example be described by structural features (e.g. acid chlorides, alkaline earth compounds, polyoxyalkylenes), a significant precursor (e.g. Castor Oil or Tallow) or by a more general description (e.g. Resins or Waxes.)

materials. The chemical composition of crude oils from different producing regions, and even from within a particular formation, can vary tremendously. An “average” crude contains 84% carbon, 14% hydrogen, 1-3% sulfur, and approximately 1.0 % nitrogen, 1.0% oxygen and 0.1% minerals and salts. Crude oils are identified by the predominant proportion of similar hydrocarbon molecules and are further classified by viscosity, specific gravity (density) and by American Petroleum Institute (API) gravity. API gravity is an indication of the gasoline potential of crude oil with higher API gravity indicating greater gasoline potential and thus more valuable crude oil. Paraffinic crude oils are rich in straight chain and branched paraffins, have a high API gravity, low density and viscosity, and contain a higher concentration of gasoline grade naphtha. Naphthenic crude oils contain mainly cycloparaffins and aromatic hydrocarbons, have low API gravity, higher density and viscosity and contain residual materials and heteroatoms (e.g. sulfur, nitrogen, and oxygen-containing hydrocarbon analogs).

1.2 Physical-Chemical Properties

The physical-chemical properties of crude oil are summarized in Table 1. Petroleum (crude oil) is not a uniform substance since its physical and chemical properties vary from oilfield to oilfield and can even vary within wells at the same oilfield. At one extreme, it is a light, mobile, straw-colored liquid. At the other extreme, it is a highly viscous, semi-solid, black substance from which little can be distilled at atmospheric pressure before thermal decomposition occurs. The lower molecular weight components of petroleum possess moderate to high water solubility while higher molecular weight fractions tend to form emulsions in water. The lower molecular weight components of petroleum have high vapor pressure while higher molecular weight fractions tend to possess negligible to low vapor pressure.

Table 1. Physical-Chemical Properties of Petroleum¹	
Property	Petroleum (Crude Oil)
CASRN	8002-05-9
Molecular Weight	Complex Mixture
Physical State	Light, mobile, straw-colored liquid to highly viscous, semi-solid, black substance
Melting Point	-30 to 30 °C (measured pour points)
Boiling Point	-1 to 565 °C (measured distillation range)
Vapor Pressure	142.5 mm Hg at 37 °C (measured Alaska North Slope crude oil); 165.8 mm Hg at 37 °C (measured Arabian medium crude oil); 337.5 mm Hg at 37 °C (measured Alif Temen crude oil); 202.5 mm Hg at 37 °C (measured Amna Libya crude oil); 97.5 mm Hg at 37 °C (measured Ashtart Tunisia crude oil); 45 mm Hg at 37 °C (measured Atkinson Canadian crude oil); 142.5 mm Hg at 37 °C (measured Alberta sweet mixed blend Canadian crude oil); 180 mm Hg at 37 °C (measured United Arab Emirate crude oil); 270 mm Hg at 37 °C (measured Beryl North Sea crude oil); 247.5 mm Hg at 37 °C (measured Bombay High Indiacrude oil);

Table 1. Physical-Chemical Properties of Petroleum¹	
	<p><u>Aliphatic Fraction^{2,3}</u> 266 mm Hg (estimated >C5-C6); 47.9 mm Hg (estimated >C6-C8); 4.8 mm Hg (estimated >C8-C10); 0.48 mm Hg (estimated >C10-C12); 0.036 mm Hg (estimated >C12-C16); 8.3×10^{-4} mm Hg (estimated >C16-C21);</p> <p><u>Aromatic Fraction^{2,3}</u> 98.8 mm Hg (estimated >C5-C7); 28.9 mm Hg (estimated >C7-C8); 4.8 mm Hg (estimated >C8-C10); 0.48 mm Hg (estimated >C10-C12); 0.036 mm Hg (estimated >C12-C16); 8.3×10^{-4} mm Hg (estimated >C16-C21); 3.3×10^{-7} mm Hg (estimated >C21-C35)</p>
Dissociation Constant (pK _a)	Not applicable
Henry's Law Constant	<p><u>Aliphatic Fraction^{2,3}</u> 0.74 atm-m³/mol (estimated >C5-C6); 1.12 atm-m³/mol (estimated >C6-C8); 1.79 atm-m³/mol (estimated >C8-C10); 2.69 atm-m³/mol (estimated >C10-C12); 11.7 atm-m³/mol (estimated >C12-C16); 110 atm-m³/mol (estimated >C16-C21);</p> <p><u>Aromatic Fraction^{2,3}</u> 0.0052 atm-m³/mol (estimated >C5-C7); 0.0060 atm-m³/mol (estimated >C7-C8); 0.011 atm-m³/mol (estimated >C8-C10); 0.003 atm-m³/mol (estimated >C10-C12); 0.001 atm-m³/mol (estimated >C12-C16); 0.0029 atm-m³/mol (estimated >C16-C21); 1.5×10^{-5} atm-m³/mol (estimated >C21-C35)</p>
Water Solubility	30 mg/L (measured at 5 °C; Norman Wells crude oil) ^{1,4} ; 29-33 mg/L (measured at 20 °C; Norman Wells crude oil) ^{1,4} ; 31.8-33.5 mg/L (measured at 22 °C; Norman Wells crude oil) ^{1,4} ; 33 mg/L (measured at 20 °C; Norman Wells crude oil) ^{1,4} ; 25.02 mg/L (measured at 22 °C; Alberta crude oil) ^{1,4} ; 35.1 mg/L (measured at 22 °C; Swan Hills) ^{1,4} ; 29.01 mg/L (measured at 22 °C; Prudhoe Bay crude oil) ^{1,4} ; 23.66-25.5 mg/L (measured at 22 °C; Lago Medio crude oil) ^{1,4} ; 10.42 mg/L (measured at 22 °C; Kopanoar crude oil) ^{1,4} ; 28.62 mg/L (measured at 22 °C; Murban crude oil) ^{1,4} ; 29.6 mg/L (measured at 22 °C; Mobil A crude oil) ^{1,4} ;

Table 1. Physical-Chemical Properties of Petroleum¹	
	<p>58 mg/L (measured at 22 °C; Mobil B crude oil)^{1,4}</p> <p><u>Aliphatic Fraction^{2,3}</u> 36 mg/L (estimated >C5-C6); 5.4 mg/L (estimated >C6-C8); 0.43 mg/L (estimated >C8-C10); 0.034 mg/L (estimated >C10-C12); 7.6 × 10⁻⁴ mg/L (estimated >C12-C16);</p> <p><u>Aromatic Fraction^{2,3}</u> 1,800 mg/L (estimated >C5-C7); 520 mg/L (estimated >C7-C8); 65 mg/L (estimated >C8-C10); 25 mg/L (estimated >C10-C12); 5.8 mg/L (estimated >C12-C16); 0.65 mg/L (estimated >C16-C21); 6.6 × 10⁻³ mg/L (estimated >C21-C35)</p>
Log K _{ow}	2 to > 6 (estimated)
<p>¹ American Petroleum Institute Petroleum HPV Testing Group. Test Plan and Robust Summary for Crude Oil. November 15, 2003. Available online at http://www.epa.gov/oppt/chemrtk/pubs/summaries/crdoilct/c14858tc.htm as of December 7, 2010.</p> <p>² Total Petroleum Hydrocarbon Criteria Working Group; Human Health Risk- Based Evaluation of Petroleum Release Sites: Implementing the Working Group Approach Volume 5. June 1999.</p> <p>³ The Total Petroleum Hydrocarbon Working Group subdivided aromatics and aliphatic hydrocarbons of crude oil into 13 aliphatic and aromatic fractions and provided representative physical-chemical properties for these fractions.</p> <p>⁴ Results based on the water soluble fraction of total benzene, toluene, ethyl benzene + xylenes (combined concentration) and naphthalenes. The lower molecular weight components may dissolve in water while other fractions may float and spread out on water where they may form emulsions.</p>	

2. General Information on Exposure

2.1 Production Volume and Use Pattern

The Crude Oil category chemicals had an aggregated production and/or import volume in the United States greater than one billion pounds in calendar year 2005.

No industrial processing and uses and commercial and consumer uses were reported for the chemical.

2.2 Environmental Exposure and Fate

The environmental fate properties are provided in Table 2. The low molecular weight aliphatic and aromatic components of petroleum are expected to possess high mobility in soil while the heavier molecular weight constituents are expected to possess low mobility. Four petroleum samples were tested for biodegradation over the course of a 28 day incubation period by cultures

of *Acinetobacter* sp. and a mixed microbial consortium isolated from sediment obtained from Shizugawa Bay, Japan. The oils were initially heat treated to 100 °C in order to remove the low molecular weight constituents that may be considered readily biodegradable. Roughly 12-20% biodegradation was observed for the crude oil samples over 28 days with exposure to *Acinetobacter* sp. and 19-34% biodegradation was observed for exposure to the mixed microbial cultures. Petroleum added to unamended seawater samples was 3% degraded (1% mineralized) in 18 days; however, addition of nitrate and phosphate nutrients to the seawater increased the degradation and mineralization to 70 and 42%, respectively over the 18 day incubation period. Seven petroleum samples were degraded 11-50% after 42 days using nitrate and phosphate amended seawater obtained off the coast of California. Gas-chromatography analysis indicated that paraffinic components (both linear and branched) degraded at a greater rate than aromatic components and the asphaltic components were very slow to degrade. In general, n-alkanes are readily degraded under environmental conditions. Branched-chain or iso-alkanes are less readily biodegraded, but they do ultimately biodegrade. The degradation of cycloalkanes has not been extensively studied, but the ring structure is more resistant to biodegradation, and degrades more slowly. Aromatic hydrocarbons are also resistant to biodegradation, but a few microorganisms are able to utilize them. High molecular weight compounds, the tars and asphaltenes, show little to no degradation, and are persistent. Volatilization of the components of petroleum is expected to be moderate to high. The rate of hydrolysis is expected to be negligible since the substances in petroleum do not possess functional groups that hydrolyze under environmental conditions. The components of petroleum are expected to possess low (P1) to high (P3) persistence and low (B1) to high (B3) bioaccumulation potential.

Conclusion: Petroleum (crude oil) is a complex mixture of paraffinic, naphthenic and aromatic hydrocarbons ranging in carbon number from C1 to >C60. Petroleum typically also contain smaller amounts of heteroatom compounds, metals (either complexed with porphyrins or as salts of carboxylic acids) and hydrogen sulfide. Petroleum is not a uniform substance since its physical and chemical properties vary from oilfield to oilfield and can even vary within wells at the same oilfield. At one extreme, it is a light, mobile, straw-colored liquid. At the other extreme, it is a highly viscous, semi-solid, black substance. The lower molecular weight components of petroleum possess moderate to high water solubility while higher molecular weight fractions tend to form emulsions in water. The lower molecular weight components of petroleum have high vapor pressure while higher molecular weight fractions tend to possess negligible to low vapor pressure. The lighter weight aliphatic and aromatic components of petroleum will have high mobility in soils while the heavier molecular weight constituents will possess low mobility. Volatilization is expected to be moderate to high for most constituents of petroleum. The rate of hydrolysis is negligible since paraffins, naphthenes and the aromatic hydrocarbons contained in petroleum do not possess functional groups that hydrolyze under environmental conditions. The rate of atmospheric photooxidation is expected to be slow to rapid for most components of petroleum. The components of petroleum are expected to possess low (P1) to high (P3) persistence and low (B1) to high (B3) bioaccumulation potential.

Table 2. Environmental Fate Properties of Petroleum¹	
Property	Petroleum (Crude Oil)
CASRN	8002-05-9
Photodegradation Half-life	0.37 – 6.5 days (estimated) ^{1,2}
Hydrolysis Half-life	Stable
Biodegradation	12-20% after 28 days (not readily biodegradable) ³ ; 19-34% after 28 days (not readily biodegradable) ³ ; 70% after 18 days in seawater amended with nitrate and phosphate nutrients ⁴ ; 11-50% after 42 days in seawater amended with nitrate and phosphate nutrients ⁵
Bioaccumulation Factor	38 – 5.1 × 10 ⁵ (estimated) ^{2,6}
Log K _{oc}	1.6 – 4.2 (estimated) ^{2,6}
Fugacity (Level III Model) ^{2,6}	
Air (%)	19.4 – 48.4
Water (%)	41.1 – 69.4
Soil (%)	0.8 – 39.4
Sediment (%)	0.2 – 11.5
Persistence ⁷	P1(low) – P3 (high)
Bioaccumulation ⁷	B1 (low) – B3 (high)
<p>¹ American Petroleum Institute Petroleum HPV Testing Group. Test Plan and Robust Summary for Crude Oil. November 15, 2003. Available online at http://www.epa.gov/oppt/chemrtk/pubs/summaries/crdoilct/c14858tc.htm as of December 7, 2010.</p> <p>² Estimated values for benzene, n-butane, n-hexane, toluene, cyclohexane, n-decane, n-tetradecane and naphthalene.</p> <p>³ Sugiura K. Ishihara M. Shimauchi, T. Harayama S. 1997. Physicochemical properties and biodegradability of crude oil. <i>Environ. Sci. Technol.</i> 31:45-51.</p> <p>⁴ Atlas RM and Barth R. 1972. Degradation and mineralization of petroleum in sea water. Limitation by nitrogen and phosphorus. <i>Biotechnol. Bioeng.</i> 14:309-18.</p> <p>⁵ Atlas R. 1975. Effects of temperature and crude oil composition on petroleum biodegradation. <i>Appl. Microbiol.</i> 30(3) 396-403.</p> <p>⁶ U.S. EPA. 2010. Estimation Programs Interface Suite™ for Microsoft® Windows, v4.00. U.S. Environmental Protection Agency, Washington, DC, USA. Available online from: http://www.epa.gov/opptintr/exposure/pubs/episuitedi.htm as of December 7, 2010.</p> <p>⁷ Federal Register. 1999. Category for Persistent, Bioaccumulative, and Toxic New Chemical Substances. <i>Federal Register</i> 64, Number 213 (November 4, 1999) pp. 60194–60204.</p>	

3. Human Health Hazard

A summary of health effects data submitted for SIDS endpoints is provided in Table 3.

Acute Oral Toxicity

Beryl light crude oil

Sprague-Dawley rats (5/sex) were administered a single dose of Beryl light crude oil via gavage at 5000 mg/kg and observed for 14 days. No mortalities were observed.

LD₅₀ > 5000 mg/kg

Lost Hills light crude oil

Rats (sex/strain/number not specified) were administered Lost Hills light crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 5000 mg/kg

MCSL crude oil

Rats (sex/strain/number not specified) were administered MCSL crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 5000 mg/kg

Arab light crude oil

Rats (sex/strain/number not specified) were administered Arab light crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 5000 mg/kg

Belridge heavy crude oil

Rats (sex/strain/number not specified) were administered Belridge heavy crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 5000 mg/kg

Wilmington crude oil

Male mice (sex/strain/number not specified) were administered Wilmington crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 16,000 mg/kg

Recluse crude oil

Male mice (sex/strain/number not specified) were administered recluse crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 16,000 mg/kg

Mixed petroleum crude oil

Male mice (sex/strain/number not specified) were administered mixed petroleum crude oil via an unspecified oral route. No further methods were specified.

LD₅₀ > 10,000 mg/kg

Acute Inhalation Toxicity

Athabasca oil sands synthetic crude oil

Sprague-Dawley rats (5/sex) were exposed via whole-body inhalation to Athabasca oil sands synthetic crude oil as an aerosol at 4.0 mg/L for 6 hours and observed for 14 days. No mortality was observed (Stubblefield *et al.*, 1989).

LD₅₀ > 4 mg/L

Athabasca oil sands synthetic crude oil

Swiss-Webster mice (5/sex) were exposed via whole-body inhalation to Athabasca oil sands synthetic crude oil as an aerosol at 4.0 mg/L for 6 hours and observed for 14 days. Five of the 10 mice died within the 14-day observation period (Stubblefield *et al.*, 1989).

LD₅₀ = ~ 4 mg/L

Acute Dermal Toxicity

Beryl light crude oil

New Zealand White rabbits (3/sex) were administered Beryl crude light oil via dermal application at 2000 mg/kg to intact or abraded clipped skin, under occluded conditions, for 24 hours and observed for 14 days. No mortalities were observed.

LD₅₀ > 2000 mg/kg

Lost Hills light crude oil

Rabbits (sex/strain/number not specified) were administered Lost Hills light crude oil via dermal application. No further methods were specified.

LD₅₀ > 2000 mg/kg

MCSL crude oil

Rabbits (sex/strain/number not specified) were administered MCSL crude oil via dermal application. No further methods were specified.

LD₅₀ > 2000 mg/kg

Arab light crude oil

Rabbits (sex/strain/number not specified) were administered Arab light crude oil via dermal application. No further methods were specified.

LD₅₀ > 2000 mg/kg

Belridge heavy crude oil

Rabbits (sex/strain/number not specified) were administered Belridge heavy crude oil via dermal application. No further methods were specified.

LD₅₀ > 2000 mg/kg

Repeated-Dose Toxicity

High-nitrogen crude oil

Sprague-Dawley rats (10/sex/dose) were administered high-nitrogen crude oil (API-HNC-1) via the dermal route at 250 or 2500 mg/kg-day on intact skin under occluded conditions for 6 hours/day, 5 days/week for 4 weeks. An additional control group (20/sex) was sham-treated. Overt signs of toxicity, dermal responses, body weights, food consumption, hematology, clinical chemistry and organ weights were examined. Males exposed to 250 mg/kg-day did not gain as much weight as controls and males exposed to 2500 mg/kg-day showed a significant decrease in body weight as compared to controls (statistical significance not reported). Females exposed to 2500 mg/kg-day had increased absolute and relative liver weights and increased absolute adrenal weights and males exposed to 2500 mg/kg-day had increased relative liver weight (details on absolute liver weight not provided). These data are summarized in TSCATS (OTS0000381 and OTS0000381-1).

LOAEL (male) = 2500 mg/kg-day (based on reduced body weight gain)

NOAEL (male) = 250 mg/kg-day

NOAEL (female) = 2500 mg/kg-day (based on no effects observed at the highest dose tested)

Lost Hills light crude oil

Sprague-Dawley rats (10/sex/dose) were administered Lost Hills light crude oil (50% non-aromatics, 35.3% < 3-ring polyaromatic hydrocarbons [PAHs], 10.2% 3 – 5 ring PAHs, 2.4% sulfur polyaromatic compounds [PACs] and 5.4% nitrogen PACs) via dermal application, to shorn skin under open conditions at 0 (untreated control), 30, 125 or 500 mg/kg-day, 5 days/week for 13 weeks. Animals were fitted with collars to minimize the ingestion of the Lost Hills light crude oil. Endpoints included body weight, hematology, clinical chemistry, organ weights, and histopathology. Additional groups of 10 males/dose were administered crude oil at 0 and 500 mg/kg-day and evaluated for male reproductive health. Measurements included weights of testes and cauda epididymides, number of sperm and percent normal sperm in the cauda and number of spermatids in the testes. Minimal skin irritation (flaking) was observed at the exposure site. No treatment-related mortality was observed. Decreases in red blood cells (RBCs), hemoglobin and hematocrit were observed in males at 500 mg/kg-day. Changes in clinical chemistry at 500 mg/kg-day included decreased calcium (in males), increased glucose (in both sexes), increased urea nitrogen (in males) and decreased potassium (in females). Glucose was also elevated in males at 125 mg/kg-day and in females at 30 mg/kg-day, but glucose was not elevated in females at 125 mg/kg-day. Increases in absolute and relative liver weights were observed in both males and females at 500 mg/kg-day. Hyperplasia and associated dermal inflammatory cell infiltration were observed at all dose levels. Histopathological effects in the liver included multifocal, mononuclear cell infiltration (in three males and two females) and multifocal hepatocellular vacuolation (in three females) at 500 mg/kg-day. Atrophy of the thymus was observed in one male and two females at 500 mg/kg-day. Hypertrophy and hyperplasia of follicular thyroid epithelium were observed in both sexes at all dose levels (incidence rate not specified). No effects were observed on the reproductive health of males.

LOAEL = 30 mg/kg-day (based on hypertrophy and hyperplasia of follicular thyroid epithelium)

NOAEL = Not established

Belridge heavy crude oil

Sprague-Dawley rats (10/sex/dose) were administered Belridge heavy crude oil (37.3% non-aromatics, 41.7% < 3-ring PAHs, 15.7% 3-5 ring PAHs, 2.9% sulfur PACs and 8.4% nitrogen

PACs) to shorn skin under open conditions at 0 (untreated control), 30, 125 or 500 mg/kg-day, 5 days/week for 13 weeks. Animals were fitted with collars to minimize the ingestion of the Belridge heavy crude oil. Endpoints included body weight, hematology, clinical chemistry, organ weights and histopathology. Additional groups of 10 males/dose were administered crude oil at 0 and 500 mg/kg-day and evaluated for male reproductive health. Measurements included weights of testes and cauda epididymides, number of sperm and percent normal sperm in the cauda and number of spermatids in the testes. Minimal skin irritation (flaking) was observed at the exposure site. No treatment-related mortality was observed. Reduced weight gain was observed at 500 mg/kg-day. Decreases in RBCs, hemoglobin and hematocrit in both sexes and a decrease in platelets in males were observed at 500 mg/kg-day. Changes in clinical chemistry at 500 mg/kg-day included decreased uric acid in both sexes, increased urea nitrogen in females and reduced alanine transaminase and potassium in females. Cholesterol was elevated in females at doses \geq 125 mg/kg-day. Hyperplasia and associated dermal inflammatory cell infiltration were observed at all treatment levels. Increases in absolute and relative liver weights were observed in both males and females at 500 mg/kg-day. Decreases in absolute (both sexes) and relative (females only) thymus weights were also observed at 500 mg/kg-day. Elevated relative liver weights were observed in males at 125 mg/kg-day. Increased cellularity was observed in the bone marrow of two males at 30 and 125 mg/kg-day, in six males at 500 mg/kg-day and in 9 of 10 females at an unspecified dose level. Focal necrosis was noted in the bone marrow of two males at 500 mg/kg-day. Histopathological effects in the liver at 500 mg/kg-day consisted of hepatocellular vacuolation in one male and one female and mononuclear cell infiltration in one male. Atrophy of the thymus was observed in six males and seven females at 500 mg/kg-day. Hypertrophy and hyperplasia of follicular thyroid epithelium was observed in a few animals at all dose levels (details not specified). Effects on the reproductive health of males were not noted. **LOAEL = 30 mg/kg-day** (based on hypertrophy and hyperplasia of follicular thyroid epithelium in both sexes and increased cellularity of the bone marrow of males)
NOAEL = Not established

Reproductive Toxicity

Lost Hills light crude oil

In the repeated-dose toxicity study described previously, male Sprague-Dawley rats administered Lost Hills light crude oil via dermal application at 500 mg/kg-day did not exhibit changes in the weights of testes and cauda epididymides, number of sperm and the percent of normal sperm in the cauda or number of spermatids in the testes.

Developmental Toxicity

Prudhoe Bay heavy crude oil

In a prenatal developmental toxicity study, pregnant Sprague-Dawley rats (8 – 11/dose) were administered Prudhoe Bay heavy crude oil via gavage at 1 or 2 mL/kg-day (887 or 1774 mg/kg-day)⁵ on gestation days 6 – 17. Animals were sacrificed on gestation day 18. Measured

⁵ Volume of crude oil was converted to units of mg/kg-day using an API gravity of 28 (supplied in the sponsor's test plan), which is equivalent to a density of 0.8871 g/mL.

endpoints included the numbers and position of implantations, resorptions and dead fetuses, fetal weights and gross appearance of fetuses. No maternal mortality was observed. Reductions in body weight gain were observed in dams receiving ≥ 1 mL/kg-day. Developmental effects included reduced fetal weights and fetal crown-rump length, increases in the incidence of resorptions and the number of dead fetuses, and a decrease in the number of live fetuses at ≥ 1 mL/kg-day. Examination of fetuses for skeletal and visceral abnormalities was not conducted.
LOAEL (maternal/developmental toxicity) = 887 mg/kg-day (based on reductions in maternal body weight, reduced fetal weights and fetal crown-rump length, increases in the incidence of resorptions and the number of dead fetuses, and a decrease in the number of live fetuses)
NOAEL (maternal/developmental toxicity) = Not established

Belridge heavy crude oil

In a prenatal developmental toxicity study, pregnant Sprague-Dawley rats (12/group) were administered Belridge heavy crude oil (77% paraffins and naphthenes, 15% polynuclear aromatic content and 2% asphaltenes) via the dermal route under open conditions at 0 (sham control), 30, 125 or 500 mg/kg-day on gestation days 0 – 19. Animals were fitted with collars to minimize the ingestion of the Belridge heavy crude oil. One group of females was sacrificed on day 20 and an additional group of females (exposed to 0 or 500 mg/kg-day) was allowed to deliver and was sacrificed, along with their offspring, on postpartum day 4. Measured endpoints included maternal body weights, food consumption and serum chemistry (parameters not specified), number of corpora lutea, number and location of implantations, fetal weight and sex and external, skeletal and visceral anomalies. Skin irritation was observed in dams administered 500 mg/kg-day and included erythema, edema, scabs and open sores. Red vaginal discharge was also observed at 500 mg/kg-day. Reductions in maternal body weight and food consumption and an increase in relative liver weight were all observed at 500 mg/kg-day. Total bilirubin was reduced by 38%, compared to controls, at 500 mg/kg-day. Among the dams allowed to deliver, 2/12 dams had no viable offspring. Developmental effects were observed only at 500 mg/kg-day and included an increase in the mean number and percent of resorptions, a decrease in litter size, a decrease in mean fetal weight for all viable fetuses, incomplete ossification of the nasal bones and caudal centra and an increased incidence of pup mortality during lactation. These data are summarized in TSCATS (OTS0509763-9).

LOAEL (maternal toxicity) = 500 mg/kg-day (based on reductions in maternal body weight)

NOAEL (maternal toxicity) = 125 mg/kg-day

LOAEL (developmental toxicity) = 500 mg/kg-day (based on an increase in the mean number and percent of resorptions, a decrease in litter size, a decrease in mean fetal weight for all viable fetuses, incomplete ossification of the nasal bones and caudal centra and an increased incidence of pup mortality during lactation)

NOAEL (developmental toxicity) = 125 mg/kg-day

Lost Hills light crude oil

(1) In a prenatal developmental toxicity study, pregnant Sprague-Dawley rats (12/group) were administered Lost Hills light crude oil (78% paraffins and naphthenes, 8% polynuclear aromatic content and 1% asphaltenes) via the dermal route under open conditions at 0 (sham control), 125, 500 or 2000 mg/kg-day on gestation days 0 – 19. Animals were fitted with collars to minimize the ingestion of the Lost Hills light crude oil. One group of females was sacrificed on day 20 and an additional group of females (exposed to 0 or 2000 mg/kg-day) was allowed to deliver and

was sacrificed, along with their offspring, on postpartum day 4. Measured endpoints included maternal body weights, food consumption and serum chemistry (parameters not specified), number of corpora lutea, number and location of implantations, fetal weight and sex and external, skeletal and visceral anomalies. Clinical observations consisted of red vaginal discharge, paleness of skin and slight skin irritation at 2000 mg/kg-day. Reductions in weight gain and food consumption were observed at doses \geq 500 mg/kg-day. Absolute and relative thymus weights were statistically significantly decreased in animals treated with 2000 mg/kg-day and a non-statistically significant decrease in absolute thymus weight was observed at 500 mg/kg-day. Relative liver weight was increased at doses \geq 500 mg/kg-day. Effects on serum chemistry at 2000 mg/kg-day included increases in aspartate aminotransferase, alanine aminotransferase, alkaline phosphatase, cholesterol, albumin/globulin ratio, phosphorus and sorbitol dehydrogenase. Decreases in triglycerides and total bilirubin were observed at doses \geq 500 mg/kg-day. Among the dams allowed to deliver, 3/12 dams had no viable offspring and another 2 dams had their entire litter die by postpartum day 3. Developmental effects included an increase in the mean number and percent of resorptions, a decrease in litter size, a decrease in mean fetal weight, reduced pup weight at birth and on lactation day 4 and a decrease in pup survival during lactation at 2000 mg/kg-day. Incomplete ossification was more common in fetuses of treated dams, with the following skeletal areas being significantly ($p < 0.05$) affected: nasal bones at doses \geq 125 mg/kg-day, thoracic centra and sternbrae at 2000 mg/kg-day and caudal centra at 125 and 2000 mg/kg-day. These data are summarized in TSCATS (OTS0509763-9).

LOAEL (maternal toxicity) = 500 mg/kg-day (based on reductions in maternal weight gain)

NOAEL (maternal toxicity) = 125 mg/kg-day

LOAEL (developmental toxicity) = 125 mg/kg-day (based on incomplete ossification of fetal nasal bones)

NOAEL (developmental toxicity) = Not established

(2) In a prenatal developmental toxicity study, pregnant Sprague-Dawley rats (12/group) were administered Lost Hills light crude oil via the dermal route at 0 (sham control), 125, 500 or 1000 mg/kg-day to intact skin under open conditions on gestation days 0 – 19. Animals were fitted with collars to minimize the ingestion of the Lost Hills light crude oil. Dams were sacrificed on postpartum day 21 and their litters on postpartum day 28. One female in the 500 mg/kg/day group had excessive salivation one day during gestation. One female in the 1000 mg/kg/day group was sacrificed moribund on gestation day 14. The animal had decreased motor activity, decreased stool, red vaginal discharge, pale extremities and felt cool to the touch. Upon macroscopic examination, this female was noted to have enlarged adrenals. Uterine examination revealed total litter resorptions (13 fetuses), which would account for the red vaginal discharge. Scabbing was observed at the dose site of three treated animals (doses not specified). This finding was considered to be animal-induced (via scratching or biting). One high-dose female exhibited erythema and flaking of the skin at the dose site. Females in the 1000 mg/kg/day group gained significantly ($p < 0.05$) less weight towards the end of gestation. Overall weight gain (days 0 – 20) was also significantly ($p < 0.05$) affected for this group as overall weight gain decreased with increasing dose level. No adverse body weight effects were observed during lactation. Upon necropsy, mottled lungs were seen in one female from the high-dose group. This finding was not considered to be related to treatment due to its isolated occurrence. A significant ($p < 0.05$) decrease in pup body weight was first noted in the high-dose female pups

on postpartum day 21. By day 28, both sexes weighed significantly ($p < 0.05$) less than control pups. There were no treatment-related effects on mating, fertility and gestation indices, duration of gestation, the numbers of stillborn and live pups, pup survival or the number of implantation sites per litter. In addition, pup development evaluations, which included monitoring of pinna detachment, hair growth, incisor eruption, eye opening and surface righting, showed no evidence of treatment-related effects. One mid- and one high-dose pup had enlarged ventricles of the brain, but the effect was not statistically significant or dose-dependent. This variation is occasionally seen during visceral examination of the brain of small fetuses. Both pups demonstrating this finding were smaller than their littermates. Varied findings were noted during pup necropsy, but were not considered to be treatment-related due to presence in the control group or lack of a dose-related response. These data are summarized in TSCATS (OTS0509763-9).

LOAEL (maternal/developmental toxicity) = 1000 mg/kg-day (based on reduced maternal body weight gains during gestation and reduced pup body weights and body weight gain)

NOAEL (maternal/developmental toxicity) = 500 mg/kg-day

Genetic Toxicity – Gene Mutation

In vitro

Beryl light crude oil

In a modified Ames assay, *S. typhimurium* strain TA98 was exposed to Beryl light crude oil in dimethyl sulfoxide (DMSO) at concentrations of 1, 3, 5, 7, 10, 15, 25 and 50 $\mu\text{L}/\text{plate}$ with metabolic activation. Positive and negative controls were used and responded appropriately. The number of revertants was elevated in cultures exposed to the test substance.

Beryl light crude oil was mutagenic in this assay.

Arab light crude oil

A modified Ames assay was conducted on Arab light crude oil. No further details were provided.

Arab light crude oil was mutagenic in this assay.

MCSL crude oil

A modified Ames assay was conducted on MCSL light crude oil. No further details were provided.

MCSL crude oil was mutagenic in this assay.

Belridge heavy crude oil

A modified Ames assay was conducted on Belridge heavy crude oil. No further details were provided.

Belridge heavy crude oil was mutagenic in this assay.

Lost Hills light crude oil

A modified Ames assay was conducted on Lost Hills light crude oil. No further details were provided.

Lost Hills light crude oil was not mutagenic in this assay.

Genetic Toxicity – Chromosomal Aberrations

In vitro

Lost Hills light crude oil

In a cytogenetic assay, CHO cells were exposed to Lost Hills light crude oil in DMSO at concentrations of 1, 2.5, 5, 10, 15 or 20 $\mu\text{L}/\text{mL}$ culture medium for 2 hours with metabolic activation. Positive and negative controls were used and responded appropriately. Cytotoxicity was observed at concentrations $\geq 10 \mu\text{L}/\text{mL}$. No increase in the proportion of cells with structural chromosomal aberrations was observed in response to the test substance.

Lost Hills light crude oil did not show evidence of chromosomal aberrations in this assay.

Belridge heavy crude oil

In a cytogenetic assay, CHO cells were exposed to Belridge heavy crude oil in DMSO at concentrations of 1, 2.5, 5, 10, 15 or 20 $\mu\text{L}/\text{mL}$ culture medium for 2 hours with metabolic activation. Positive and negative controls were used and responded appropriately. Cytotoxicity was observed at concentrations $\geq 10 \mu\text{L}/\text{mL}$. No increase in the proportion of cells with structural chromosomal aberrations was observed in response to the test substance.

Belridge heavy crude oil did not show evidence of chromosomal aberrations in this assay.

Wilmington crude oil

In a sister chromatid exchange assay, human lymphocytes were exposed to Wilmington crude oil in Tween 80 at concentrations of 20 or 30 mg/L with activation or 40 or 50 mg/L without metabolic activation. Positive and negative controls were used and responded appropriately. An increase in sister chromatid exchange was not observed in response to exposure to crude oil.

Wilmington crude oil did not show evidence of sister chromatid exchange in this assay.

In vivo

Lost Hills light crude oil

In a micronucleus assay, Sprague-Dawley rats (5/sex/dose) were administered Lost Hills light crude oil via the dermal route at 0, 30, 125 or 500 mg/kg-day for 13 weeks. No cytotoxicity was observed. Exposure to the Lost Hills light crude oil did not induce an increase in the formation of micronuclei. The use of a positive control was not noted.

Lost Hills light crude oil did not induce micronuclei in this assay.

Wilmington crude oil

In a sister chromatid exchange assay, Sch:ICR mice (3 males/group) were administered Wilmington crude oil via intraperitoneal injection at doses of 1800, 3600 or 7200 mg/kg. Positive and negative controls were used and responded appropriately. A slight, but significant ($p < 0.05$), increase in sister chromatid exchange was observed at the highest dose of crude oil tested.

Wilmington crude oil induced sister chromatid exchange in this assay.

Additional Information

Skin Irritation

Beryl light crude oil

In the acute dermal study described previously, New Zealand White rabbits administered Beryl light crude oil via the dermal route at 2000 mg/kg exhibited slight to moderate skin irritation after 26 and 72 hours.

Beryl light crude oil was moderately irritating to rabbit skin in this study.

Lost Hills light crude oil

New Zealand White rabbits (6/dose; sex not specified) were administered 0.5 mL of Lost Hills light crude oil via the dermal route at each of six shorn test sites (three intact and three abraded sites on each animal) and observed for 7 days. Four of the sites (two intact and two abraded) were covered with an occlusive dressing and two sites remained open. Two sites were wiped gently after 4 hours and the remaining four sites were wiped after 24 hours. The mean scores (average of scores at 24, 48 and 72 hours) for erythema and edema at the intact sites exposed for 4 hours were 1.69 and 1.3, respectively. The primary irritation index for occluded sites was 2.8 and 3.6 for exposures of 4 and 24 hours, respectively. Conditions of exposure (intact or abraded; occluded or open) had little effect on dermal response.

Lost Hills light crude oil was slightly irritating to rabbit skin in this study.

Arab light crude oil

New Zealand White rabbits (6/dose; sex not specified) were administered 0.5 mL of Arab light crude oil via the dermal route at each of six shorn test sites (three intact and three abraded sites on each animal) and observed for 7 days. Four of the sites (two intact and two abraded) were covered with an occlusive dressing and two sites remained open. Two sites were wiped gently after 4 hours and the remaining four sites were wiped after 24 hours. The mean scores (average of scores at 24, 48 and 72 hours) for erythema and edema at the intact sites exposed for 4 hours were 0.9 and 0.1, respectively. Moderate erythema was observed at the sites exposed for 24 hours. Conditions of exposure (intact or abraded; occluded or open) had little effect on dermal response.

Arab light crude oil was moderately irritating to rabbit skin in this study.

Eye Irritation

Beryl light crude oil

New Zealand White rabbits (6/dose) were administered 0.1 mL of Beryl light crude oil into one eye and observed for 72 hours. No irritation of the cornea or iris was observed. The irritation score for the conjunctivae was 4.0 after 1 hour and 1.0 after 72 hours.

Beryl light crude oil was irritating to rabbit eyes in this study.

Sensitization

Lost Hills light crude oil

In a Buehler test, guinea pigs (10/sex/dose) were administered 0.4 mL of 15% Lost Hills light crude oil in mineral oil to shorn skin under occluded conditions for 6 hours once per week for 3 weeks. Challenge patch application was performed 14 days after the last induction dose had been applied. Dual challenge patches (containing 10 and 15% test substance in mineral oil) were applied to fresh application sites of previously shorn skin of the animals. The patches were then occluded for 6 hours. On the day following challenge patch application, the skin was depilated and 2 hours later, scored for signs of sensitization. The sites were examined after a further 48 hours but this time without depilation. The dermal response was not considered to be positive. **Lost Hills light crude oil was not sensitizing to guinea pig skin in this study.**

Carcinogenicity

Crude oil “C”

C3H mice (50 males) were administered crude oil “C” via the dermal route 2 times/week at a dose of 50 mg/application for 18 months or until grossly observable cancer was found. Thirty-three percent of the animals developed tumors and the average time to appearance of the first tumor was 76 weeks.

Crude oil “C” was carcinogenic to mice in this study.

Crude oil “D”

C3H mice (50 males) were administered crude oil “D” via the dermal route 2 times/week at a dose of 50 mg/application for 18 months or until grossly observable cancer was found. Fifty-six percent of the animals developed tumors and the average time to appearance of the first tumor was 64 weeks.

Crude oil “D” was carcinogenic to mice in this study.

San Joaquin Valley heavy crude oil

C3H mice (25/sex/dose) were administered San Joaquin Valley heavy crude oil via the dermal route 3 times/week at a dose of 25 mg/application for ≤ 105 weeks. Survival of treated mice was reduced compared to the controls. Dermal irritation at the test site first appeared at 271 days and males developed irritation earlier than females. Irritation included necrosis, cracking, separation and sloughing of skin. Tumor incidence was 29% for squamous cell carcinomas and 7% for fibrosarcomas in treated mice, compared to 0% for both tumor types in control mice. The average time to appearance of the first tumor was 62 weeks.

San Joaquin Valley heavy crude oil was carcinogenic to mice in this study.

Iranian light crude oil

Male C3H/HeJ mice (40/dose) were administered 25 μ L of Iranian light crude oil via the dermal route 3 times/week. Exposures began between 4 and 6 weeks of age and continued until death of the animals. A negative control group was dosed with the same volume of acetone alone and a positive control group received 25 μ L of 0.1% methylcholanthrene in acetone. Mice were examined daily for mortality and monthly for skin lesions. Mean survival time of animals exposed to Iranian light crude oil did not differ from negative controls treated with the same volume of acetone, both of which survived greater than 2 times as long as negative controls treated with 25 μ L of 0.1% methylcholanthrene. Two papillomas and two squamous carcinomas were recorded in the area of application, along with two mesenchymal tumors in other areas

following dermal exposure to crude oil. Of the 40 oil-exposed animals, 29 were diagnosed as having hyperkeratosis of the skin in the treated area and a few animals exhibited ulcerative dermatitis. Fifteen oil treated animals displayed hepatocellular carcinomas compared with only five in the acetone treated group. Although tumor incidence was not statistically different from acetone controls, the presence of tumors was considered biologically significant because of the zero incidence in historical acetone controls. These data are summarized in TSCATS (OTS0000648).

Iranian light crude oil was carcinogenic to mice in this study.

The International Agency for Research on Cancer (IARC) has determined that Crude Oil is not classifiable as to its carcinogenicity to humans (Group 3) (IARC, 1989).

Epidemiology

In an epidemiology study, blood samples were taken from 68 individuals (control n = 42) exposed to crude oil during the cleanup of a spill and the cytogenetic damage was assessed as determined by sister chromatid exchange (SCE). Workers in the high-pressure cleaner worker category (n = 23) showed a statistically significant increase in their SCE frequency as compared to controls (Perez-Cadahia *et al.*, 2007).

In an epidemiology study of workers exposed to crude oil, workers in the job category “upstream operator offshore” had an excess risk of hematologic neoplasm (blood and bone marrow), RR 1.90, 95% CI 1.19 – 3.02 and multiple myeloma, RR 2.49, 95% CI 1.21-5.13 as compared to that of the general working population (Kirkeleit *et al.*, 2008).

Conclusion: The acute toxicity of CASRN 8002-05-9 is low in rats and mice by the oral route, low to moderate in rats and moderate in mice by the inhalation route and low in rabbits by the dermal route. A 28-day dermal repeated-dose toxicity study in rats showed reduced body weight gain in males at 2500 mg/kg-day and no effects in females at 2500 mg/kg-day (highest dose tested). The NOAEL is 250 mg/kg-day in males and 2500 mg/kg-day in females. A 90-day dermal repeated-dose toxicity study in rats showed hypertrophy and hyperplasia of follicular thyroid epithelium in males and females at 30 mg/kg-day; the NOAEL was not established. In a second 90-day dermal repeated-dose toxicity study in rats, both males and females showed hypertrophy and hyperplasia of follicular thyroid epithelium and males showed increased bone marrow cellularity at 30 mg/kg-day; the NOAEL was not established. No specific reproductive toxicity studies are available. In the dermal repeated-dose toxicity study, no effects on the reproductive organs were observed in male rats treated with 500 mg/kg-day (only dose tested). In a prenatal developmental toxicity study in rats administered CASRN 8002-05-9 via gavage, reduced maternal body weight was observed at 887 mg/kg-day; the NOAEL for maternal toxicity was not established. Signs of developmental toxicity consisted of reduced fetal weight, reduced fetal crown-rump length, increased numbers of resorptions and the number of dead fetuses and decreased number of live fetuses at 887 mg/kg-day; the NOAEL for developmental toxicity was not established. In a prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 500 mg/kg-day; the NOAEL for maternal toxicity is 125 mg/kg-day. Signs of developmental toxicity consisted of increased

number of resorptions, decreased litter size, decreased fetal weight, incomplete ossification of nasal bones and caudal centra and an increased incidence of pup mortality during lactation at 500 mg/kg-day; the NOAEL for developmental toxicity is 125 mg/kg-day. In another prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 500 mg/kg-day; the NOAEL for maternal toxicity is 125 mg/kg-day. Incomplete ossification of fetal nasal bones was observed in pups at 125 mg/kg-day; the NOAEL for developmental toxicity was not established. In a third prenatal developmental toxicity study in rats administered CASRN 8002-05-9 dermally, reduced maternal body weight was observed at 1000 mg/kg-day; the NOAEL for maternal toxicity is 500 mg/kg-day. Signs of developmental toxicity consisted of reduced pup body weight and body weight gain at 1000 mg/kg-day; the NOAEL for developmental toxicity is 500 mg/kg-day. CASRN 8002-05-9 was mutagenic in bacteria *in vitro* but did not show evidence of chromosomal aberrations in mammalian cells *in vitro*. CASRN 8002-05-9 did induce chromosomal aberrations in mice *in vivo*. CASRN 8002-05-9 is irritating to rabbit skin and eyes and did not induce sensitization in guinea pigs. CASRN 8002-05-9 is carcinogenic to mice via dermal exposure.

Table 3. Summary of the Screening Information Data Set as Submitted under the U.S. HPV Challenge Program – Human Health Data	
Endpoints	SPONSORED CHEMICAL Crude Oil (8002-05-9)
Acute Oral Toxicity LD₅₀ (mg/kg)	> 5000
Acute Dermal Toxicity LD₅₀ (mg/kg)	> 2000
Acute Inhalation Toxicity LC₅₀ (mg/L)	> 4
Repeated-Dose Toxicity NOAEL/LOAEL Dermal (mg/kg-day)	NOAEL = Not established LOAEL = 30
Reproductive Toxicity	Data Gap

Table 3. Summary of the Screening Information Data Set as Submitted under the U.S. HPV Challenge Program – Human Health Data	
Endpoints	SPONSORED CHEMICAL Crude Oil (8002-05-9)
Developmental Toxicity NOAEL/LOAEL Oral gavage (mg/kg-day)	
Maternal Toxicity	NOAEL = Not established LOAEL = 887 (lowest dose tested)
Developmental Toxicity	NOAEL = Not established LOAEL = 887 (lowest dose tested)
Developmental Toxicity NOAEL/LOAEL Dermal (mg/kg-day)	
Maternal Toxicity	NOAEL = 125 LOAEL = 500
Developmental Toxicity	NOAEL = Not established LOAEL = 125
Genetic Toxicity – Gene Mutations <i>In vitro</i>	Positive
Genetic Toxicity – Chromosomal Aberrations <i>In vitro</i>	Negative
Genetic Toxicity – Chromosomal Aberrations <i>In vivo</i>	Positive
Additional Information Skin Irritation Eye Irritation	Positive Positive
Skin Sensitization Carcinogenicity	Negative (guinea pig) Positive (mice)

Measured data in bold

4. Hazard to the Environment

A summary of aquatic toxicity data submitted for SIDS endpoints is provided in Table 4.

Acute Toxicity to Fish

Crude oil (0.5% paraffinic)

Rainbow trout (*Oncorhynchus mykiss*) were exposed to crude oil (0.5% paraffinic) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. The loading rates were 0, 1.4, 3.2, 8.5, 21 and 50 mg/L. Analytical monitoring of test concentrations consisted of measurements of benzene, toluene, ethylbenzene, and xylene (BTEX) concentrations and mean measured concentrations were 0, 0.123, 0.295, 0.822, 1.78 and 4.39 mg/L, respectively. Mortalities were limited to fish exposed to loading rates of 21 (5/10 fish) and 50 mg/L (10/10 fish). No mortalities were observed at a loading rate concentration of 8.5 mg/L.

96-h LL₅₀ = 21 mg/L

Crude oil (3% paraffinic)

Rainbow trout (*Oncorhynchus mykiss*) were exposed to crude oil (3% paraffinic) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading rates were 0, 2.7, 6.8, 16, 40 and 109 mg/L. Analytical monitoring of test concentrations consisted of measurements of BTEX concentrations and mean measured concentrations were 0, 0.085, 0.261, 0.505, 1.13 and 1.96 mg/L, respectively. Mortalities were limited to fish exposed to loading rates of 40 (5/10 fish) and 109 mg/L (10/10 fish). No mortalities were observed at a loading rate concentration of 16 mg/L.

96-h LL₅₀ = 41 mg/L

Prudhoe Bay crude oil

(1) Slimy sculpins (*Cottus cognatus*; ≥ 12 juveniles/group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours.

96-h LC₅₀ = 3 mg/L

(2) Threespine sticklebacks (*Gasterosteus aculeatus*; ≥ 12 adults/group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours.

96-h LC₅₀ > 6.9 mg/L

ECOTOX database (Reference No. 5622).

(3) Sockeye salmon (*Oncorhynchus nerka*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours. Tests were conducted in freshwater and seawater. **96-h LC₅₀ = 1.1 mg/L** (seawater)

96-h LC₅₀ = 2.2 mg/L (freshwater)

ECOTOX database (Reference No. 5622).

(4) Chinook salmon (*Oncorhynchus tshawytscha*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours.

96-h LC₅₀ = 1.5 mg/L

ECOTOX database (Reference No. 5622).

(5) Chinook salmon (*Oncorhynchus tshawytscha*; 8/group) were exposed to unspecified measured concentrations of Prudhoe Bay crude oil as WAFs under flow-through conditions for 96 hours. The test was performed in triplicate.

96-h LC₅₀ = 7.46 mg/L

ECOTOX database (Reference No. 5622).

(6) Arctic char (*Salvelinus alpinus*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as water-soluble fractions under static conditions for 96 hours.

96-h LC₅₀ = 2.2 mg/L

ECOTOX database (Reference No. 5622).

(7) Arctic grayling (*Thymallus arcticus*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as water-soluble fractions under static conditions for 96 hours.

96-h LC₅₀ = 2.0 mg/L

ECOTOX database (Reference No. 5622).

(8) Dolly Varden (*Salvelinus malma*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours. Tests were conducted in freshwater and seawater.

96-h LC₅₀ = 1.4 mg/L (seawater)

96-h LC₅₀ = 2.7 mg/L (freshwater)

(9) Fourhorn sculpin (*Myoxocephalus quadricornis*) were exposed to Prudhoe Bay crude oil at measured concentrations of 27, 39.5, 49.6 or 52.1 mg/L under static-renewal conditions for 96 hours.

96-h LC₅₀ = 42 mg/L

(10) Pink salmon (*Oncorhynchus gorbuscha*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours. Tests were conducted in freshwater and seawater.

96-h LC₅₀ = 3.7 mg/L (seawater)

96-h LC₅₀ = 8.0 mg/L (freshwater)

(11) Coho salmon (*Oncorhynchus kisutch*; ≥ 12 /group) were exposed to five to seven unspecified measured concentrations of Prudhoe Bay crude oil as a water-soluble fraction under static conditions for 96 hours.

96-h LC₅₀ = 1.5 mg/L

ECOTOX database (Reference No. 5622).

(12) Coho salmon (*Oncorhynchus kisutch*; 12/group) were exposed to crude oil as a water-soluble fraction at unspecified measured concentrations under static conditions for 96 hours.

96-h LC₅₀ = 10.4 mg/L

ECOTOX database (Reference No. 477).

Cook Inlet crude oil

(1) Pink salmon (*Oncorhynchus gorbuscha*; 10 – 15/group) were exposed to Cook Inlet crude oil as a water-soluble fraction at unspecified measured concentrations under static conditions for 96 hours.

96-h LC₅₀ = 1.5 mg/L at 4 °C

96-h LC₅₀ = 1.7 mg/L at 8 °C

96-h LC₅₀ = 1.8 mg/L at 12 °C

(2) Coho salmon (*Oncorhynchus kisutch*) were exposed to Cook Inlet crude oil as a water-soluble fraction at unspecified concentrations under flow-through conditions for 96 hours. The LC₅₀ was based upon measured concentrations.

96-h LC₅₀ = 0.73 – 1.1 mg/L

Crude oil (geographic source not specified)

Pink salmon (*Oncorhynchus gorbuscha*; 25/group) were exposed to crude oil as a water-soluble fraction at measured concentrations of 0.21, 0.40, 0.58 or 0.87 mg/L under flow-through conditions for 96 hours.

96-h LC₅₀ = 1.2 mg/L

Crude oil (Arabian Medium)

(1) Inland silversides (*Menidia beryllina*) were exposed to crude oil (arabian medium) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. The loading rates were 0 (control), 1.58, 1.65, 3.03, 4.15, and 5.18 and mg/L. Mean measured concentrations were 0 (control), 0.83, 1.38, 2.93, 4.38, and 4.79 mg/L, respectively.

96-h LC₅₀ = 5.0 mg/L

(2) Inland silversides (*Menidia beryllina*) were exposed to crude oil (arabian medium) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. Measure concentrations were not specified.

96-h LC₅₀ = 15.6 mg/L

(3) Inland silversides (*Menidia beryllina*) were exposed to crude oil (arabian medium) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. The loading rates were not specified. Mean measured concentrations were 0 (control), 2.5, 5.4, 6.9, 9.0 and 14.5 mg/L, respectively.

96-h LC₅₀ = 14.5 mg/L

Crude oil (Arabian Medium)

(1) Sheepshead minnows (*Cyprinodon variegatus*) were exposed to crude oil (arabian medium) as water accommodated fractions (WAFs) under flow-through test system for 96 hours. The loading rates were 0 (control), 3.12, 5.09, 4.72, 5.94, and 6.73 and mg/L. Mean measured concentrations were 0 (control), 1.99, and 5.42 mg TPH/L, respectively.

96-h LC₅₀ = 4.0 mg/L

(2) Sheepshead minnows (*Cyprinodon variegatus*) were exposed to crude oil (arabian medium) as water accommodated fractions (WAFs) under flow-through conditions in a closed test system for 96 hours. The loading rates were not specified. Mean measured concentrations were 0 (control), 1.7, 2.6, 4.8, 4.7 and 5.7 mg/L, respectively.

96-h LC₅₀ = 5.7 mg/L

Crude oil (Prudhoe Bay)

(1) Inland silversides (*Menidia beryllina*) were exposed to crude oil (Prudhoe Bay) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. Measure concentrations were not specified.

96-h LC₅₀ = 14.80 mg/L

(2) Inland silversides (*Menidia beryllina*) were exposed to crude oil (Prudhoe Bay) as water accommodated fractions (WAFs) under flow-through test system for 96 hours. Measure concentrations were not specified.

96-h LC₅₀ > 19.86 mg/L

Crude oil (Bass Strait)

Crimson-spotted rainbow fish (*Melanotaenia fluviatilis*) were exposed to crude oil (bass strait) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. The loading rates were 0 (control), 5, 10, 20, 40, and 80% water soluble fraction of crude oil. Mean measured concentrations were 0 (control), 0.2, 0.4, 0.7, 1.4, and 2.7 mg/L, respectively.

96-h LC₅₀ = 1.28 mg/L

Crude oil (Louisiana Sweet)

Inland silversides (*Menidia beryllina*) were exposed to crude oil (Louisiana Sweet) as water accommodated fractions (WAFs) under static-renewal conditions in a closed test system for 96 hours. Measure concentrations were not specified.

96-h LC₅₀ > 3.0 mg/L

Crude oil (Alaska North Slope)

(1) Inland silversides (*Menidia beryllina*) were exposed to crude oil (Alaska North slope) as water accommodated fractions (WAFs) under flow-through test system for 96 hours. Measure concentrations were not specified.

96-h LC₅₀ = 26.4 mg/L

Acute Toxicity to Aquatic Invertebrates

Crude oil (0.5% paraffinic)

Kelp forest mysid shrimp (*Holmesiyysis costata*) were exposed to crude oil (0.5% paraffinic) as WAFs under static-renewal conditions for 96 hours. The loading rates were 0, 0.14, 0.28, 1.4, 3.5 and 11 mg/L. Analytical monitoring of test concentrations consisted of measurements of BTEX concentrations and all measured concentrations were ≤ 0.5 mg/L. Mortality was 0, 10, 10, 5, 75 and 100% at loading rates of 0, 0.14, 0.28, 1.4, 3.5 and 11 mg/L, respectively.

96-h LL₅₀ = 2.7 mg/L

Crude oil (3% paraffinic)

Kelp forest mysid shrimp (*Holmesiyysis costata*) were exposed to crude oil (3% paraffinic) as WAFs under static-renewal conditions for 96 hours. The loading rates were 0, 0.6, 1.7, 3.6, 8.3 and 21 mg/L. Analytical monitoring of test concentrations consisted of measurements of BTEX concentrations and all measured concentrations were ≤ 0.247 mg/L. Mortality was 5, 10, 15, 30, 100 and 100% at loading rates of 0, 0.6, 1.7, 3.6, 8.3 and 21 mg/L, respectively.

96-h LL₅₀ = 4.1 mg/L

Kuwait crude oil

(1) Mysid shrimp (*Mysidopsis bahia*) were exposed to Kuwait crude oil (68.56% paraffins, 15.69% aromatics and 11.86% naphthenes) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading rates were not specified. The measured concentrations were 0 (control), 1.05, 1.54, 2.85, 3.62, and 5.63 mg/L

96-h LC₅₀ = 0.56 mg/L

Crude oil (Alaska North Slope)

Mysid shrimp (*Mysidopsis bahia*) were exposed to Alaska North slope crude oil as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h LC₅₀ = 2.6 mg/L

Crude oil (Arabian Medium)

Mysid shrimp (*Americamysis bahia*) were exposed to Arabian medium slope crude oil as WAFs under flow-through test system for 96 hours. Mean measured concentrations were 0 (control), 2.4, 3.1, 4.7, 11.6 mg TPH/L. Loading rates were not specified.

96-h LC₅₀ = 11.6 mg/L

Crude oil (Louisiana Sweet)

Mysid shrimp (*Americamysis bahia*) were exposed to Louisiana sweet crude oil as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h LC₅₀ = 2.7 mg/L

Crude oil (Alaska North Slope)

Mysid shrimp (*Americamysis bahia*) were exposed to Alaska North slope crude oil as WAFs under flow-through test system for 96 hours. The loading or measure rates were not specified.

96-h LC₅₀ = 9.6 mg/L

Crude oil (Pitas Point)

Water fleas (*Daphnia magna*) were exposed to crude oil (Pitas point) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 5.9 mg/L

Amauligak crude oil

Daphnia magna were exposed to Amauligak crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.66 mg/L

Maclean and Doe (1989).

Sable Island crude oil

Daphnia magna were exposed to Sable Island crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted in triplicate. The EC₅₀ was calculated by combining data from the three tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 0.41 mg/L

Maclean and Doe (1989).

Hibernia crude oil

Daphnia magna were exposed to Hibernia crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.1 mg/L

Bent Horn crude oil

Daphnia magna were exposed to Bent Horn crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy

48-h EC₅₀ = 1.1 mg/L

Maclean and Doe (1989).

Western sweet crude oil blend

Daphnia magna were exposed to Western sweet crude oil blend as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test

was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.12 mg/L

Transmountain crude oil

Daphnia magna were exposed to Transmountain crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.1 mg/L

Maclean and Doe (1989).

Norman Wells crude oil

Daphnia magna were exposed to Norman Wells crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted in triplicate. The EC₅₀ was calculated by combining data from the three tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.66 mg/L

Maclean and Doe (1989).

Venezuelan BCF-22 crude oil

Daphnia magna were exposed to Venezuelan BCF-22 crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 1.72 mg/L

Lago Medio crude oil

Daphnia magna were exposed to Lago Medio crude oil as a water-soluble fraction at unspecified concentrations under static conditions in sealed test chambers for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 3.22 mg/L

Maclean and Doe (1989).

Prudhoe crude oil

Daphnia magna were exposed to Prudhoe crude oil as a water-soluble fraction at unspecified concentrations in sealed test chambers under static conditions for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using gas chromatography.

48-h EC₅₀ = 3.4 mg/L

Maclean and Doe (1989).

Atkinson crude oil

Daphnia magna were exposed to Atkinson crude oil as a water-soluble fraction at unspecified concentrations in sealed test chambers under static conditions for 48 hours. The test was

conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 0.61 mg/L

Maclean and Doe (1989).

Venture condensate crude oil

Daphnia magna were exposed to Venture condensate crude oil as a water-soluble fraction at unspecified concentrations in sealed test chambers under static conditions for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using fluorescence spectroscopy.

48-h EC₅₀ = 0.83 mg/L

Maclean and Doe (1989).

Tarsuit crude oil

Daphnia magna were exposed to Tarsuit crude oil as a water-soluble fraction at unspecified concentrations in sealed test chambers under static conditions for 48 hours. The test was conducted twice. The EC₅₀ was calculated by combining data from both tests and was based upon concentrations measured using gas chromatography.

48-h EC₅₀ = 0.85 mg/L

Maclean and Doe (1989).

Crude oil (Oseberg)

Water fleas (*Daphnia magna*) were exposed to crude oil (Oseberg) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 13.3 mg/L

Crude oil (Hondo)

Water fleas (*Daphnia magna*) were exposed to crude oil (Hondo) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 11.8 mg/L

Crude oil (Dos Cuadras)

Water fleas (*Daphnia magna*) were exposed to crude oil (Dos Cuadras) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 4.6 mg/L

Crude oil (Carpinteria)

Water fleas (*Daphnia magna*) were exposed to crude oil (Carpinteria) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 5.5 mg/L

Crude oil (BCF 24)

Water fleas (*Daphnia magna*) were exposed to crude oil (BCF 24) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 10.6 mg/L

Crude oil (Santa)

Water fleas (*Daphnia magna*) were exposed to crude oil (Santa) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 7.5 mg/L

Crude oil (Sockeye)

Water fleas (*Daphnia magna*) were exposed to crude oil (Sockeye) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 12.1 mg/L

Crude oil (West Texas Sour)

Water fleas (*Daphnia magna*) were exposed to crude oil (West Texas Sour) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 28.7 mg/L

Crude oil (West Texan Intermediate)

Water fleas (*Daphnia magna*) were exposed to crude oil (West Texan Intermediate) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 12.7 mg/L

Crude oil (Iranian Light)

Water fleas (*Daphnia magna*) were exposed to crude oil (Iranian Light) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 12.3 mg/L

Crude oil (Waxy Light Heavy Blend)

Water fleas (*Daphnia magna*) were exposed to crude oil (waxy light heavy blend) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 4.8 mg/L

Crude oil (Arabian Light)

Water fleas (*Daphnia magna*) were exposed to crude oil (Arabian light) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 11.4 mg/L

Crude oil (Arabian Medium)

Water fleas (*Daphnia magna*) were exposed to crude oil (Arabian medium) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 7.4 mg/L

Crude oil (Empire)

Water fleas (*Daphnia magna*) were exposed to crude oil (empire) as WAFs under static-renewal conditions in a closed test system for 96 hours. The loading or measure rates were not specified.

96-h EC₅₀ = 17.3 mg/L

Toxicity to Aquatic Plants

No adequate data were available

Chronic Toxicity to Invertebrates

Sen crude oil

Daphnia magna were exposed to Sen crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 10, 40 and 60% at crude oil concentrations of 0.5, 1 and 2 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was reduced by 45, 52 and 68% at crude oil concentrations of 0.5, 1 and 2 mg/L, respectively. Based on the more sensitive parameter (reproduction), the EC₅₀ was between 0.5 and 1 mg/L.

0.5 mg/L < 21-d EC₅₀ < 1 mg/L

Ogarrio crude oil

Daphnia magna were exposed to Ogarrio crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 30, 100, 100 and 100% at crude oil concentrations of 1.25, 2.5, 5 and 10 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was reduced by 53, 99, 99 and 99% at crude oil concentrations of 1.25, 2.5, 5 and 10 mg/L, respectively. Based on the more sensitive parameter (reproduction), the EC₅₀ was < 1.25 mg/L.

21-d EC₅₀ < 1.25 mg/L

Caparroso crude oil

Daphnia magna were exposed to Caparroso crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 0, 0 and 50% at crude oil concentrations of 0.33, 0.67 and 1.3 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was

reduced by 12, 32 and 35% at crude oil concentrations of 0.33, 0.67 and 1.3 mg/L, respectively. Based on the more sensitive parameter (immobility), the EC₅₀ was ~ 1.3 mg/L.

21-d EC₅₀ = ~ 1.3 mg/L

Castarrical crude oil

Daphnia magna were exposed to Castarrical crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 90, 100 and 100% at crude oil concentrations of 2.7, 4.0 and 8.1 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was reduced by 83, 95 and 100% at crude oil concentrations of 2.7, 4.0 and 8.1 mg/L, respectively.

Based on both parameters, the EC₅₀ was < 2.7 mg/L

21-d EC₅₀ < 2.7 mg/L

Iride crude oil

Daphnia magna were exposed to Iride crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 100% at crude oil concentrations ≥ 3.1 mg/L. Compared to kaolin-exposed controls, the number of total progeny was reduced by 89, 98, 100, 100, 100 and 100% at crude oil concentrations of 3.1, 4.7, 9.4, 18.8, 37.5 and 75.2 mg/L, respectively. Based on the both parameters, the EC₅₀ was < 3.1 mg/L.

21-d EC₅₀ < 3.1 mg/L

Cárdenas crude oil

Daphnia magna were exposed to Cárdenas crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 0, 100, 90 and 100% at crude oil concentrations of 0.5, 1, 1.9 and 3.9 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was reduced by 27, 88, 96 and 89% at crude oil concentrations of 0.5, 1, 1.9 and 3.9 mg/L, respectively. Based on both parameters, the EC₅₀ was between 0.5 and 1 mg/L.

0.5 mg/L < 21-d EC₅₀ < 1 mg/L

Presidentes crude oil

Daphnia magna were exposed to Presidentes crude oil for 21 days in solutions that contained suspended particles of kaolin clay (2 – 4 µm). Immobility and reproduction were measured. The test included untreated controls and kaolin-exposed controls. No immobility was observed in the controls. Immobility rates were 80, 100, 100, 100 and 100% at crude oil concentrations of 3.6, 7.2, 14.5, 29 and 58 mg/L, respectively. Compared to kaolin-exposed controls, the number of total progeny was reduced by 71, 100, 100, 100 and 100% at crude oil concentrations of 3.6, 7.2, 14.5, 29 and 58 mg/L, respectively. Based on both parameters, the EC₅₀ was < 3.6 mg/L.

21-d EC₅₀ < 3.6 mg/L

Conclusion: The 96-h LC₅₀ of CASRN 8002-05-9 for fish ranges from 0.73 to 42 mg/L. The 48-h EC₅₀ of CASRN 8002-05-9 for aquatic invertebrates ranges from 0.61 to 28 mg/L. The 21-d chronic toxicity to aquatic invertebrates ranges from 0.5 to 6 mg/L.

Table 4. Summary of the Screening Information Data Set as Submitted under the U.S. HPV Challenge Program – Aquatic Toxicity Data	
Endpoints	SPONSORED CHEMICAL Crude Oil (8002-05-9)
Fish 96-h LC₅₀ (mg/L)	0.73 - 42
Aquatic Invertebrates 48-h EC₅₀ (mg/L)	0.61 – 28.7
Aquatic Plants 72-h EC₅₀ (mg/L) (growth rate) (biomass)	Data Gap
21-d Aquatic Invertebrates	0.5 – 6

5. References

American Petroleum Institute. (2008). Gasoline Blending Streams Category Assessment Document. API. Washington, DC.
<http://www.epa.gov/chemrtk/pubs/summaries/gasnecat/c13409rr3.pdf>. Accessed January 31, 2011.

Ecotox database at www.epa.gov/ecotox

IARC (International Agency for Research on Cancer). (1989). Occupational Exposures in Petroleum Refining; Crude Oil and Major Petroleum Fuels, Vol. 45. IARC Monographs on the Evaluation of Carcinogenic Risks to Humans. World Health Organization, Lyon, France.

Kirkeleit, J., Riise, T., Bratveit, M., and Moen, B. E. 2008. Increased risk of acute myelogenous leukemia and multiple myeloma in a historical cohort of upstream petroleum workers exposed to crude oil. *Cancer Causes Control* **19**, 13-23.

Perez-Cadahia, B., Lafuente, A., Cabaleiro, T., Pasaro, E., Mendez, J., and Laffon, B. 2007. Initial study on the effects of Prestige oil on human health. *Environ Int* **33**, 176-185.

Stubblefield, W. A., McKee, R. H., Kapp, R. W., Jr., and Hinz, J. P. 1989. An evaluation of the acute toxic properties of liquids derived from oil sands. *J Appl Toxicol* **9**, 59-65.

Wikipedia. 2007. Refinery Flow Diagram. Wikimedia Commons.

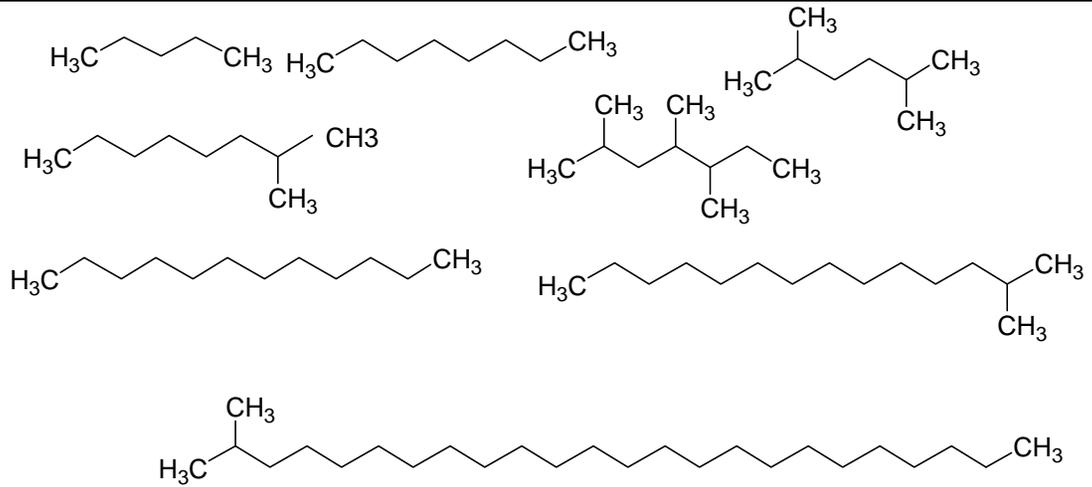
<http://en.wikipedia.org/wiki/File:RefineryFlow.png>. Accessed February 9, 2011

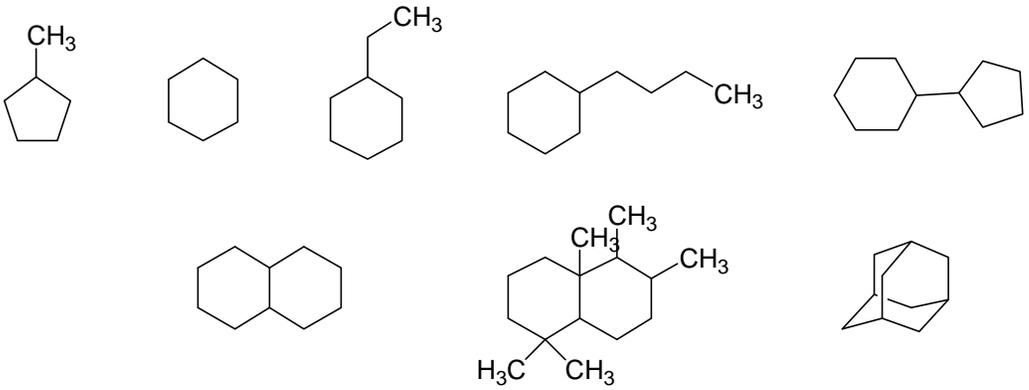
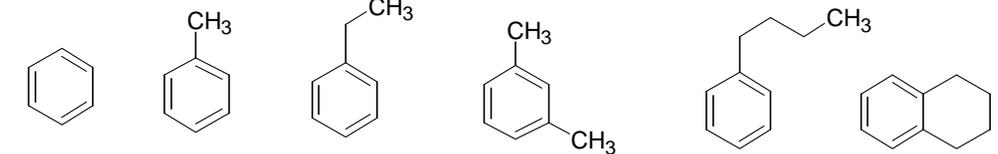
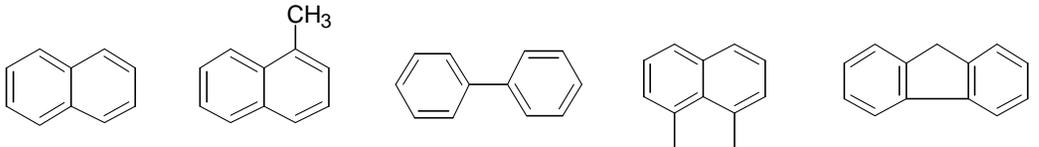
APPENDIX

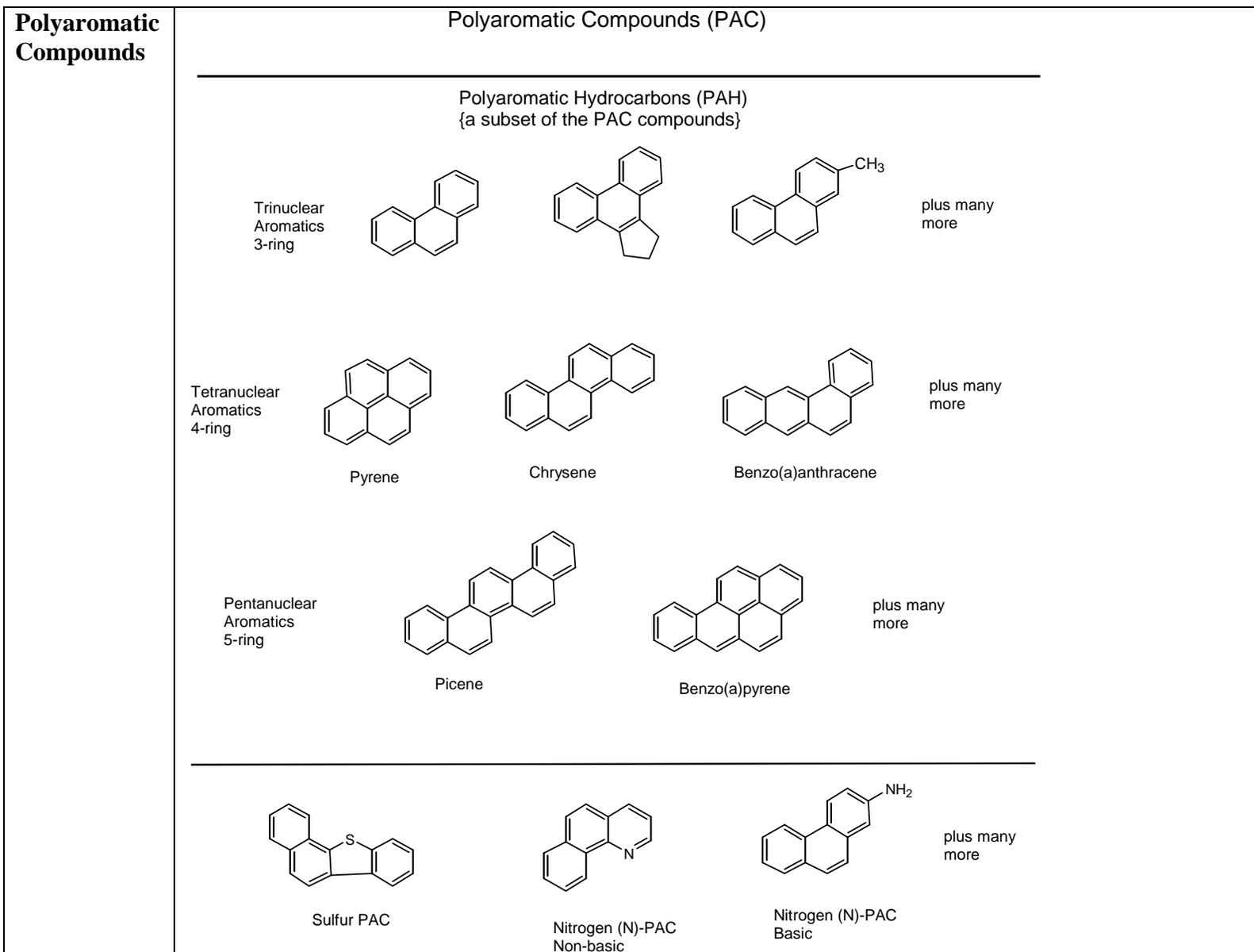
The following pages show:

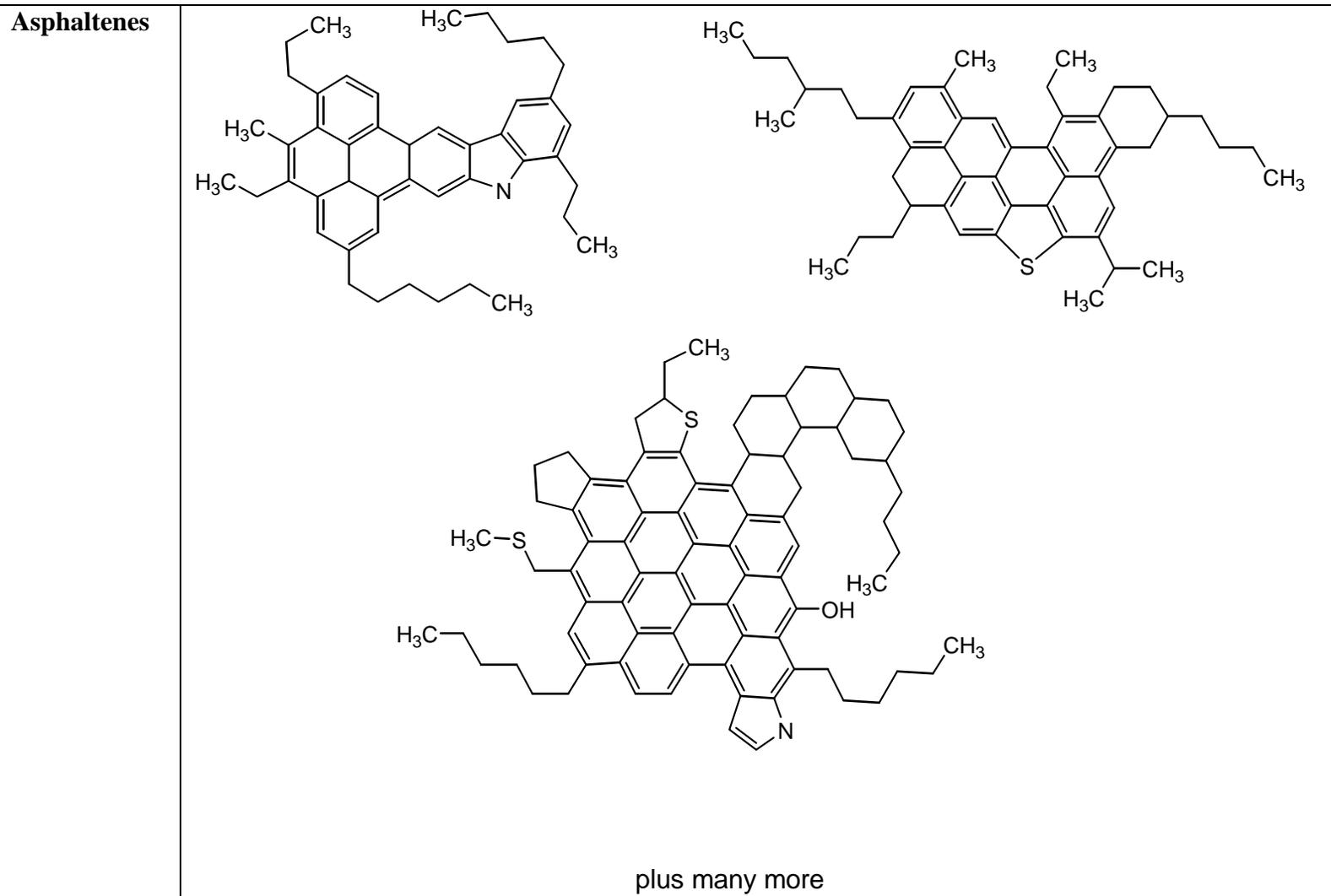
- Table 5: Representative structures for the constituents of Petroleum (Crude Oil).
- Table 6: Examples of Petroleum (Crude Oils) Covered Under CASRN 8002-05-9 (Petroleum)
- Figure 1: Representative schematic of crude oil processing

Table 5 shows representative structures for the constituents of petroleum or crude oil. The hydrocarbons that comprise crude oil – paraffins, naphthenes (cycloparaffins) and aromatics share some structural features but differ in the ratio of hydrogen to carbon atoms and how those atoms are arranged. Olefins are not present in crude oils and are formed from rearrangement of atoms during the cracking process to produce gasoline-blending streams. Paraffins occur in higher concentrations in lower boiling fractions of crude oil while the concentration of naphthenes (cycloparaffins) and aromatics increase at higher boiling ranges.

Table 5. Representative Structures for the Constituents of Petroleum (Crude Oil)	
Paraffin	 <p style="text-align: center;">Representative structures</p>

<p>Naphthenes</p>	 <p style="text-align: center;">Representative structures</p>
<p>Aromatics</p>	<p>Mononuclear Aromatics 1-ring</p>  <p style="text-align: center;">benzene toluene ethylbenzene xylene</p> <p style="text-align: center;">BTEX compounds</p> <p>Dinuclear Aromatics 2-ring</p> 

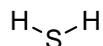




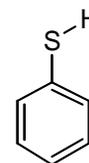
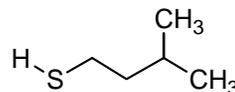
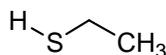
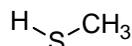
**Other
Substances**

Sulfur Compounds

In Sour Crude Oil (High sulfur content crude oils)

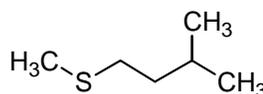
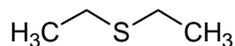


Hydrogen sulfide



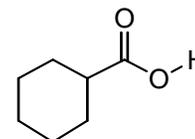
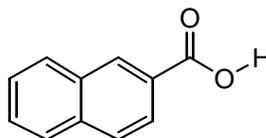
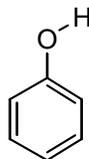
plus others

In Sweet Crude Oil (Low sulfur content crude oils)

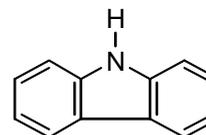
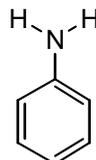
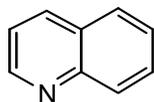


plus others
plus others

Oxygen Compounds



Nitrogen Compounds



plus others

Heavy metals, including nickel, vanadium, arsenic and iron, in trace-1000 ppm quantities
Usually found complexed with large oxygen or nitrogen compounds

Table 6. Examples of Petroleum (Crude Oils) Covered Under CASRN 8002-05-9 (Petroleum)^a

Crude Oil Source	Paraffins (% vol)	Naphthenes (% vol)	Aromatics (% vol)	Sulfur (% wt.)	API gravity (⁰ API)
Light Crude Oils					
Saudi Light	63	18	19	2.0	34
South Louisiana	79	45	19	0.0	35
Beryl	47	34	19	0.4	37
North Sea Brent	50	34	16	0.4	37
Nigerian Light	37	54	9	0.1	36
Lost Hills Light	Non-aromatics 50%		50	0.9	-
USA Mid Continent sweet	-	-	-	0.4	40
Mid Range Crude Oils					
Venezuela Light	52	34	14	1.5	30
Kuwait	63	20	24	2.4	31
USA West Texas Sour	46	32	22	1.9	32
Heavy Crude Oils					
Prudhoe Bay	27	36	28	0.9	28
Saudi Heavy	60	20	15	2.1	28
Venezuela Heavy	35	53	12	2.3	24
Belridge Heavy	Non-aromatics 37%		63	1.1	-

^aReproduced from data in Table 1 on page 7 of test plan and pages 2-3 of the robust summary.

OIL REFINERY PROCESS DESCRIPTION

Crude oil or petroleum is extracted from the ground and shipped to refineries where it is processed to produce a variety of end products. Figure 1 is a representative schematic of an oil refinery and shows several finished products from the various processes in blue. This schematic does not represent all possible processes and end products and is only meant to be an illustrative example. In the diagram, the crude oil is fed to a distillation column where gases, light and heavy naphtha (gasoline), jet and kerosene fuel, diesel oil and gas oil are separated at atmospheric pressure. The gases undergo further processing including the removal of sulfur to produce the end products of liquefied petroleum gas (LPG) and butanes. The light naphtha may be isomerized to increase octane, or hydrotreated to convert benzene to cyclohexane so that the final gasoline blend meets a benzene specification limit. The heavy naphtha is hydrotreated to remove sulfur and then reformed to improve octane and generate hydrogen for the hydrotreaters. The jet fuel, kerosene and diesel oil can be used without additional processing. The heavy bottoms produced following the atmospheric distillation undergo a vacuum distillation which produces asphalt which can be used as produced, along with light and heavy gas oil and vacuum residuum which are further processed to produce usable endproducts. The separate diagram labeled “sour water steam stripper” illustrates a process where sulfur compounds (mercaptans) are converted to more innocuous compounds to eliminate odor and instability in the gasoline blend (American Petroleum Institute, 2008). Hazard characterization documents for several of the highlighted (in blue) endproducts in Figure 1 can be found at http://iaspub.epa.gov/opthpv/hpv_hc_characterization.get_report_by_cas?doctype=2



TUESDAY, AUG 13, 2013 2:10 PM UTC

Fracking chemicals may be making oil more dangerous

"Crude oil is not supposed to explode"

LINDSAY ABRAMS

(Credit: [Steven Frame/Shutterstock](#))

Concerned over environmental and safety hazards, regulators have been demanding extra safety measures be put into place on trains carrying crude oil from North Dakota, [Bloomberg reports](#).

The U.S. Federal Railroad Administration is investigating whether chemicals used in hydraulic fracturing are corroding rail tank cars and increasing risks. Separately, three pipeline companies including Enbridge Inc. warned regulators that North Dakota oil with too much hydrogen sulfide, which is toxic and flammable, was reaching terminals and putting workers at risk.

Until last month, safety advocates' chief worry was spills in derailments. After tanker cars blew up July 6 on a train in Quebec, investigators in Canada are considering whether the composition of the crude, which normally doesn't explode, may have played a role in the accident that killed 47 people. The oil was from North Dakota's Bakken shale.

The chemicals used in hydraulic fracturing, or fracking, could be contaminating the oil, according to some experts. Hydrochloric acid, for example, is highly corrosive, and could be damaging tanker cars' interior surfaces.

Another concern is the highly flammable and toxic hydrogen sulfide, a byproduct of oil at some fracking sites:

In June, Enbridge won an emergency order to reject oil with high hydrogen-sulfide levels from its system after telling the Federal Energy Regulatory Commission that it found dangerous levels of the compound at a rail terminal in Berthold, North Dakota. In addition to being highly flammable, hydrogen sulfide in the air is an irritant and a chemical asphyxiant that can alter both oxygen utilization and the central nervous system, according to the U.S. Occupational Safety and Health Administration.

The rail industry is fighting a proposal to retrofit cars to make them less susceptible to rupture in the case of derailment. Analysts say the added costs of safety improvements could slow production if oil prices fall.



Lindsay Abrams is an assistant editor at Salon, focusing on all things sustainable. Follow her on Twitter @readinggirl, email labrams@salon.com.

Copyright © 2011 Salon.com. All rights reserved.



**U.S. Department
of Transportation**

Federal Railroad
Administration

1200 New Jersey Avenue, SE
Washington, DC 20590

JUL 29 2013

Mr. Jack Gerard
American Petroleum Institute
1220 L Street NW
Washington, DC 20005

Dear Mr. Gerard:

The Federal Railroad Administration (FRA) is reviewing potential safety issues related to the transportation of crude oil by rail. FRA has specific safety concerns about the proper classification of crude oil being shipped by rail, the subsequent determination or selection of the proper tank car packaging used for transporting crude oil, and the corresponding tank car outage requirements. This letter presents the basis for FRA’s concerns regarding these potential safety issues, notifies you of our intended path forward, and provides recommendations to help ensure compliance with the Department of Transportation’s (DOT) applicable Hazardous Materials Regulations (HMR; Title 49 Code of Federal Regulations (CFR) Parts 171–180). In addition, we request that you distribute this letter to those of your members that ship crude oil via rail.

Industry statistics demonstrate that, in terms of rail originations, crude oil shipments are the fastest growing of all hazardous materials shipped by rail. According to the Association of American Railroads’ (AAR) Annual Report of Hazardous Materials Transported by Rail for 2012, the number of crude oil originations has increased by 443 percent since 2005.

Table 1: Annual number of originations of tank cars containing crude oil, hazardous materials in tank cars, and all hazardous materials

Year	Crude Oil (4910165)	Crude Oil (4915165)	Total HM in tank cars	Total HM
2005	2,626 (71)	4,472 (45)	1,355,070	1,587,469
2006	2,573 (71)	3,510 (61)	1,370,674	1,571,665
2007	2,235 (79)	4,772 (46)	1,440,341	1,988,294
2008	7,524 (34)	4,368 (51)	1,444,194	1,999,757
2009	7,961 (28)	4,940 (42)	1,379,949	1,895,066
2010	27,979 (8)	5,746 (40)	1,525,540	2,085,361
2011	74,057 (4)	6,117 (40)	1,616,580	2,242,389
2012	257,450 (2)	7,096 (48)	1,789,529	2,474,356

In addition, crude oil transportation presents unique operating considerations because, in general, crude oil is transported in units of cars (blocks of crude oil cars within a train) and by entire unit trains consisting wholly of tank cars containing crude oil. Tank cars containing crude oil are typically loaded by one of two methods: transloading (where crude oil from cargo tanks is transferred directly into tank cars) or bulk loading operations (where crude oil is delivered to a bulk storage facility and the crude oil is then transferred from storage tanks to the railroad tank cars). In both operations, there is a blend of crude oil from a variety of sources in each tank car and the properties of the materials may vary depending on the constituent crude oils.

The HMR require that an offeror (shipper) of a hazardous material properly classify and describe the hazardous material. See 49 CFR § 171.1. To attest compliance with the HMR, a shipper of a hazardous material must also certify that the hazardous material being offered into transportation is offered in compliance with the HMR. Further, the HMR prohibit a shipper from offering hazardous material for transportation unless a tank car being used to transport such hazardous material meets the applicable HMR requirements. See, for example, 49 CFR § 171.2. Only after the properties of a hazardous material are determined and the material is properly classified can a shipper ensure compliance with the HMR. In the case of crude oil, relevant properties to properly classify the material include: flash point, corrosivity, specific gravity at loading and reference temperatures, and the presence and concentration of specific compounds such as sulfur (as found in sour crude oil). This information enables a shipper to properly classify a hazardous material and select the proper HMR-authorized packaging for transportation of that hazardous material. Such information and determination of the authorized packaging also ensures that the required tank car outage can be maintained.

FRA's safety concerns stem from the following three considerations.

1. Crude oil transported by rail often derives from different sources and is then blended, so it is critical that shippers determine the proper classification of the crude oil per the HMR. FRA audits of crude oil loading facilities indicate that the classification of crude oil being transported by rail is often based solely on Material Safety Data Sheet (MSDS) data that only provides a material classification and a range of material properties. This MSDS information is typically provided by the consignee to the shipper, and the shipper is unaware of validation of the values of the crude oil properties. Further, FRA's audits indicate that MSDS information is not gleaned from any recently conducted tests or from testing for the many different sources (wells) of the crude oil. For example, a shipper provided information to FRA showing that crude oil being transported by rail had a flash point of 68° F, or a Packing Group I hazardous material. However, the crude oil had been improperly classified as a Packing Group III material and was being transported in AAR class tank cars that were not equipped with the required design enhancements. This constituted a misuse of the crude oil HMR packaging exceptions and subsequent violations of the HMR.

The HMR contain exceptions that allow for the use of non-DOT-specification tank cars for the transportation of crude oil in certain circumstances. Title 49 CFR § 173.150(f)(1) states, “A flammable liquid with a flash point at or above 38 °C (100 °F) that does not meet the definition of any other hazard class may be reclassified as a combustible liquid.” Further, 49 CFR § 173.150(f)(3) allows materials that are classified as combustible liquids to be transported in non-DOT-specification bulk packagings.¹ As such, AAR 211 class cars are permitted to be used to transport crude oil that has been classified as a Packing Group III material with a relatively high flash point. These cars are not built and/or maintained to the standard of a DOT-specification tank car. This distinction has safety implications if the crude oil being transported has been improperly classified and actually has a lower flash point and is a Packing Group I flammable liquid hazardous material. If improperly classified, the crude oil might then be shipped in a lesser standard tank car, as occurred in the above example.

Unfortunately, the AAR standard transportation commodity code data does not distinguish between the different packing groups within the hazard class. Without further information in that regard, and in relation to the accuracy of crude oil classifications being made, FRA can only speculate as to the number of potential crude oil shipments that are being made in AAR class tank cars in violation of the HMR. Recently, the AAR Tank Car Committee introduced new requirements for tank cars constructed for ethanol and crude oil (Packing Groups I and II) service. The new requirements are intended to improve the crashworthiness of the tank cars and include a thicker shell, head protection, top fittings protection, and relief valves with a greater flow capacity. Clearly, any improper classification of crude oil and subsequent shipment in an unauthorized tank car contravenes these industry efforts to improve the safety of transporting hazardous materials, and it also contravenes the requirements of the HMR.

2. Title 49 CFR § 173.24b(a) sets the minimum tank car outage for crude oil at 1 percent at a reference temperature based on the existence of tank car insulation. A crude oil shipper must know the specific gravity of the hazardous material at the reference temperature as well as the temperature and specific gravity of the material at that temperature when loaded. This information is then used to calculate the total quantity that can be safely loaded into the car to comply with the HMR’s 1-percent outage requirement. Because it is likely that the temperature of the hazardous material loaded into the car is lower than the reference temperature, the outage after the car is loaded will likely be greater than 1 percent. If the outage is not properly calculated because the material’s specific gravity is unknown (or is provided only as a range), the tank car could be loaded such that if the temperature increases during transportation, the tank will become shell-full and the material will leak from the valve fittings or manway.

¹ Section 172.102, Special Provision B1, states, “If the material has a flash point at or above 38 °C (100 °F) and below 93 °C (200 °F), then the bulk packaging requirements of § 173.241 of this subchapter are applicable.”

Since 2004, approximately 10 percent of the one-time movement approval (OTMA) requests that FRA has received have been submitted to move overloaded tank cars.² Of these requests, 33 percent were tank cars containing flammable liquids. FRA notes that tank cars overloaded by weight are typically identified when the tank cars go over a weigh-in-motion scale at a railroad's classification yard. As indicated above, crude oil is typically moved in unit trains, and the cars in a unit train do not typically pass over weigh-in-motion scales in classification yards. Therefore it is unlikely that FRA would receive many OTMA requests for overloaded tank cars containing crude oil. Moreover, crude oil accounted for the most nonaccident releases (NARs) by commodity in 2012, nearly doubling the next highest commodity (alcohols not otherwise specified, which accounts for a comparable annual volume transported by rail). FRA's data indicates that 98 percent of the NARs involved loaded tank cars. Also, less than 2 percent of the NARs occurred at the bottom outlet valve. Product releases through the top valves and fittings of tank cars when the hazardous material expands during transportation suggest that loading facilities may not know the specific gravity of the hazardous materials loaded into railroad tank cars, resulting in a lack of sufficient outage.

3. FRA's review of the OTMA data also indicates an increasing number of incidents involving damage to tank cars in crude oil service in the form of severe corrosion of the internal surface of the tank, manway covers, and valves and fittings. A possible cause is contamination of the crude oil by materials used in the fracturing process that are corrosive to the tank car tank and service equipment. Therefore, when crude oil is loaded into tank cars, it is critical that the existence and concentration of specific elements or compounds be identified, along with the corrosivity of the materials to the tank car tanks and service equipment. Proper identification of these elements will enable a shipper to ensure the reliability of the tank car. Proper identification also enables a shipper to determine if there is a need for an interior coating or lining, alternative materials of construction for valves and fittings, and performance requirements for fluid sealing elements, such as gaskets and o-rings.

As a result of the concerns outlined above, FRA is investigating whether crude oil is being properly classified and, subsequently, whether the proper tank car packagings are being used for transportation. As part of this investigation, FRA will be requesting analytical data supporting the current classification of a shipper's crude oil, as well as information related to shipper crude oil loading practices. If analytical data regarding the current classification of crude oil is not available, FRA, in partnership with the Pipeline and Hazardous Materials Safety Administration (PHMSA), may use PHMSA's Hazardous Materials Testing Program. Under this program, a sample of a shipper's hazardous material is sent to a certified laboratory for testing, and the results of the laboratory testing are then shared with the shipper. FRA may also consider exercising its authority under 49 CFR § 109.9 to determine whether crude oil is being properly classified and transported in HMR-authorized packaging. If an investigation reveals that crude oil is not being properly classified per the HMR, FRA may use its enforcement tools to address noncompliance. Some of these enforcement tools

² Per 49 CFR § 174.50, an OTMA is required to move a nonconforming DOT-specification bulk packaging for cleaning and/or repair.

include the issuance of compliance orders, emergency orders, and civil penalties. See 49 CFR Parts 209 and 211.

FRA recommends that shippers evaluate their processes for testing, classifying, and packaging the crude oil that they offer into transportation via railroad tank car. The frequency and type of testing should be based on a shipper's knowledge of the hazardous material, with specific consideration given to the volume of hazardous material shipped, the variety of sources that the hazardous material is generated from, and the processes that generate the hazardous material.

FRA welcomes the opportunity to assist crude oil shippers in their efforts to comply with the HMR. Please contact Mr. Karl Alexy, Staff Director, Hazardous Materials Division, at (202) 493-6245 or Karl.Alexy@dot.gov to discuss this matter further.

Sincerely,

A handwritten signature in black ink, appearing to read "Thomas J. Herrmann", with a long horizontal line extending to the right.

Thomas J. Herrmann
Acting Director, Office of Safety Assurance and Compliance

STATEMENT OF ADAM SIEMINSKI

ADMINISTRATOR

ENERGY INFORMATION ADMINISTRATION

U.S. DEPARTMENT OF ENERGY

Before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

U. S. SENATE

JULY 16, 2013

Chairman Wyden, Ranking Member Murkowski, and Members of the Committee, thank you for the opportunity to appear before you today to discuss the U.S. petroleum supply system, which is changing rapidly.

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government, so the views expressed herein should not be construed as representing those of the Department of Energy or any other Federal agency. As discussed in my testimony, EIA is active in providing both data and analysis that bear directly on supplies of petroleum products in this country.

The main points of my testimony are as follows:

The United States is undergoing a dramatic change in domestic oil production. The rate of increase in domestic production continues to surpass even the most optimistic forecasts of recent years. Domestic oil production in the United States has increased significantly, and at 7.4 million barrels per day as of April 2013 is now at the highest level since October 1992. Over the five year period through calendar year 2012, domestic oil production increased by 1.5 million barrels per day, or 30%. Most of that growth occurred over the past 3 years. Lower 48 onshore production (total U.S. Lower 48 production minus production from the federal Gulf of Mexico and federal Pacific) rose more than 2 million barrels per day (bbl/d), or 64%, between February 2010 and February 2013, primarily because of a rise in productivity from oil-bearing, low-permeability rocks. Texas more than doubled its production and North Dakota's output nearly tripled over that period. Five western states — Oklahoma, New Mexico,

Wyoming, Colorado, and Utah—had production increases ranging from 23% to 64% over the same three years. This rapid growth has stressed many parts of the U.S. petroleum supply infrastructure.

Currently, transportation constraints are limiting the full impact of increased domestic crude production, but these constraints are expected to ease in the coming years. Historically, about 90% of the crude oil and petroleum products in the United States have been transported by pipeline. However, shipments of crude oil by rail from North Dakota's Bakken Shale formation have increased dramatically over the past year, reflecting both lags in adding pipeline infrastructure to transport growing volumes of crude and the ability of rail shipments to serve east coast refineries in the United States and Canada and U.S. west coast refineries, where Bakken crude has its greatest economic value as a replacement for seaborne imports of light sweet crude oil. Crude oil and petroleum products shipments by rail averaged

1.37 million barrels per day during the first half of 2013. (Up 48% from 927,000 bpd in same period in 2012) according to the Association of American Railroads (AAR), which tracks movement of commodities by rail. Crude oil accounted for an estimated 50% of the combined deliveries in the oil and petroleum products, up from 3% in 2009. This topic was discussed in the EIA This Week in Petroleum article of July 11 (See Attachment 1)

Several pipeline projects are currently under way or proposed which should increase deliveries of domestic crude from inland sources to major refining centers, primarily on the Gulf Coast. Additionally, as discussed in the EIA Today in Energy article of July 10 (See Attachment 2), more Bakken crude is being moved to market by rail. By addressing logistical constraints, these developments are leading to lower discounts for inland crudes. Even before these projects, however, increasing domestic crude production has reduced crude oil imports by almost 1.3 million bpd, or 13%, since 2008. Virtually all of the reduction in U.S. crude oil imports is reflected in lower imports from member countries of the Organization of the Petroleum Exporting Countries.

Currently the U.S. is also a very limited exporter of crude oil. Any company wanting to export crude oil must obtain a license from the Bureau of Industry and Security (BIS), which is part of the U.S.

Department of Commerce. According to the regulations published in Title 15 Part 754.2 of the Code of Federal Regulations, BIS will approve applications for licenses to export crude oil for the following kinds of transactions:

- From Alaska's Cook Inlet
- To Canada for consumption or use therein
- In connection with refining or exchange of Strategic Petroleum Reserve oil
- Of up to an average of 25,000 bbl/d of California heavy crude oil
- That are consistent with findings made by the president under an applicable statute
- Of foreign-origin crude oil where, based on written documentation satisfactory to BIS, the exporter can demonstrate that the oil is not of U.S. origin and has not been commingled with oil of U.S. origin

Monthly exports of crude oil from the United States to Canada have historically averaged 24,000 barrels per day (bbl/d) and were principally delivered to refineries in central Canada. However, U.S. exports to Canada averaged over 100,000 bbl/d over the first 4 months of 2013 as Canadian refineries, like those in the United States, are processing increased volumes of crude oil produced in Texas and North Dakota. At the same time as domestic crude oil supplies are growing, U.S. refiners face declining demand for gasoline in the U.S. market. Since 2007, demand for gasoline in the U.S. has declined by almost 600,000 bbl/d, or 6.3%, and the amount of ethanol being added to the gasoline pool has increased by almost 400,000 bbl/d (replacing about 270,000 bbl/d of petroleum gasoline after accounting for ethanol's lower energy content relative to petroleum gasoline) . Therefore, from a crude oil refiner's standpoint, demand for the refined portion of gasoline has declined by almost 900,000 bbl/d, which is the

equivalent output of 14 average sized U.S. refineries. As a response, imports of gasoline blending components have declined by almost 500,000 bbl/d, or 43%, and exports primarily from the Gulf Coast, have increased by almost 400,000 bbl/d. In 2012, 84% of the gasoline exports went to countries in Latin America. In addition, diesel demand in the U.S. declined by 450,000 bbl/d in the same time period, or by 11%, leading to a drop in diesel imports of 200,000 bbl/d and increased exports of over 700,000 bbl/d. Again, in 2012, 61% of the diesel exports went to Latin America and 35% to Europe.

Infrastructure constraints within the United States, including pipeline capacity and marine vessel availability, limit the movement of petroleum products from U.S. refining centers like the Gulf Coast to the Northeast and other regions where product demands far exceeds product production capability of within-region refining capacity. Product exports provide a way for refining centers to optimize crude runs and operations. Although expected increases in domestic demand for diesel should reduce future distillate exports, gasoline exports are likely to increase. Domestic demand is expected to continue to decline due to improvements in the efficiency of new vehicles subject to fuel economy standards that grow steadily more stringent through the 2025 model year as well as the potential increased use of higher-percentage ethanol blends and other biofuels to meet the requirements of the renewable fuel standards. Access to relatively low cost domestic crude oil and natural gas has given U.S. refineries a cost advantage in serving foreign product markets compared to refiners located in other countries who also compete to serve those markets. While access to growing supplies of domestic crude is generally advantageous for U.S. refiners, they do face some challenges in changing their input slates to accommodate the quality mix of U.S. crude production. Specifically, while virtually all of the new crude production in the U.S. is light sweet crude, much of the refining capacity in the Gulf Coast is optimized to run heavy, sour crude.

To adapt to increasing supplies of domestic light sweet crude, there are a number of alternatives available to refiners that range from little or no cost to major capital investments that would only be justified by large crude price differentials.

The low cost alternatives are those which do not meaningfully change the average gravity of the crude for which the refinery was designed. First of all, refiners can simply utilize unused light crude capacity and increase the amount of crude that they run. Since 2008, refinery runs have increased and average crude gravity has gone up, particularly on the Gulf Coast, indicating that spare light crude capacity was being utilized. By 2012, however, U.S. refiners ran at a utilization rate of 88.8 %, the highest level since 2007 and a level which many analysts view as effectively full utilization after accounting for typical levels of planned and unplanned outages.

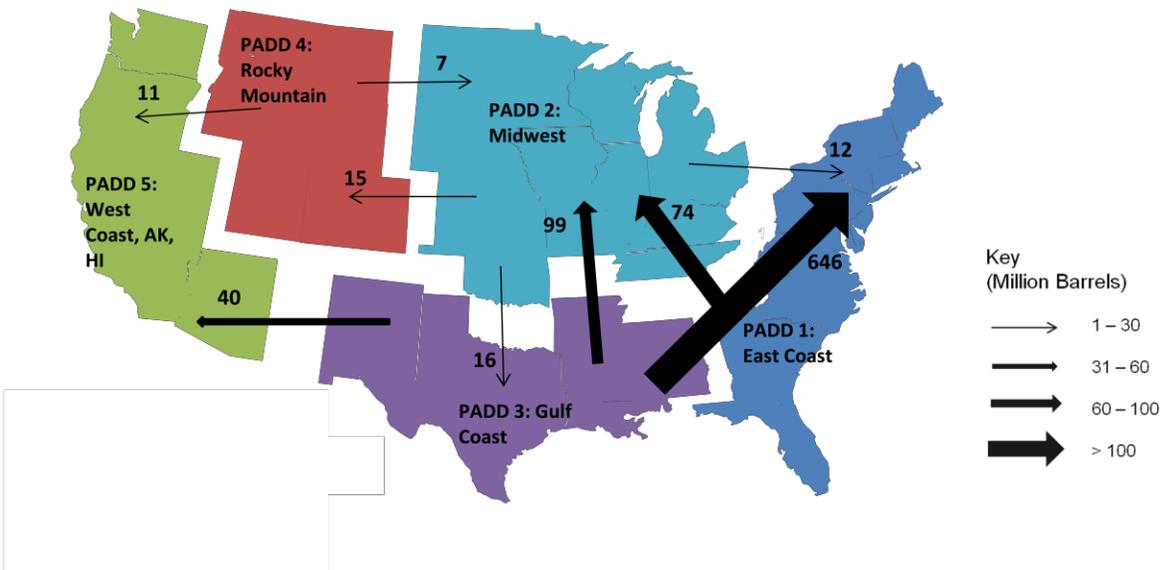
Second, refiners can simply substitute domestic light sweet crude for imported volumes, most of which, according to EIA data, has already been accomplished on the Gulf Coast. Refiners on the East and West Coasts still import significant amounts of light sweet crude, but with rail shipments and eventually pipeline additions, imports can be displaced. Lastly for a low cost alternative, refiners can blend more light sweet crude with heavier crudes to meet their desired crude quality. The ability and extent to which this can be accomplished is unique to each refinery and cannot be estimated by EIA at this time.

Other available options that involve changing the average crude quality run at a particular facility away from its typical inputs require either operational changes based on short term market incentives or capital investments which require longer term incentives. Operationally, refiners can run more light sweet crude but at the expense of total crude input, a loss that must be incentivized by relative crude prices. For longer term capital investments, there are two basic alternatives available to refiners. The

first, lower cost option would be to process light sweet crude to remove its lightest components, thereby making it more like medium gravity crude which could then be used as a substitute for imported medium crude. The more costly approach would be to invest in larger units throughout the refinery which deal with lighter components of crude such that light sweet crude could substitute for heavy crude. Again, these investments are unique to each refinery and are based on individual company investment decisions.

In spite of the dramatic changes in the U.S. petroleum supply system, prices of both domestic crude and petroleum products continue to be driven by the international market, albeit subject to short term fluctuations in the supply chain. The United States continues to rely on imported crude oil and petroleum products to meet domestic demand. In 2012, the United States imported 11.0 million bbl/d of crude oil and refined petroleum products. At the same time, the nation exported 2.7 million bbl/d of finished petroleum products and gasoline blendstocks that are also priced on the international market. While most product imports occur on the East Coast and exports from the Gulf Coast, the United States as a whole is linked by a complex logistical system which transports product and influences prices throughout the country (see Figure 1).

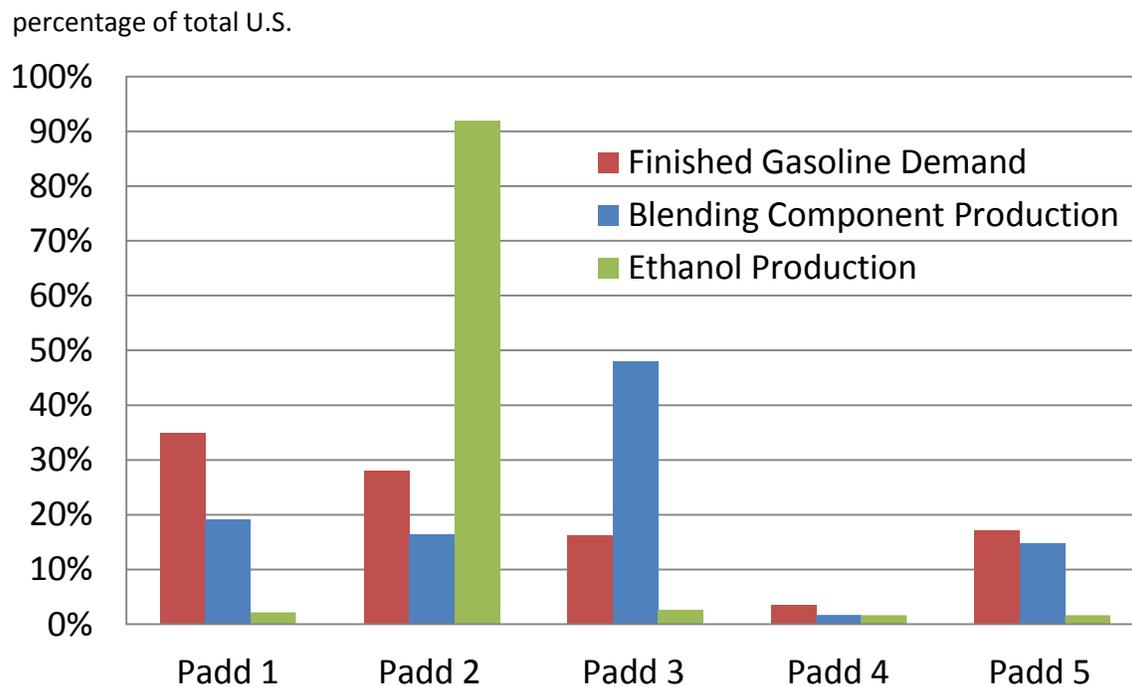
Figure 1: 2012 Total Motor Gasoline Flows Between PADDs



Note: All flows are 2012 total movements by pipeline, tanker, and barge, in millions of barrels
 Source: EIA, Petroleum Supply Monthly

The petroleum product supply system has developed over many decades to serve demand centers from both local and distant refining centers. More recently, an added complexity has resulted from the requirement to move ethanol from its predominant Midwest supply region to regions throughout the country where it is blended into the gasoline pool (see Figure 2).

Figure 2: 2012 Regional Share of Total Gasoline Demand and Production



Source: EIA, Petroleum Supply Monthly

As noted above, short-term fluctuations in regional product supply chains can cause prices in a particular region of the country to become temporarily disconnected from world and national market forces. This spring, two unplanned refinery outages in the Midwest along with delayed restarts at several others caused average retail gasoline prices to increase by 26 cents per gallon between the end of April and the middle of June. The price increase was more dramatic in parts of North Dakota and Minnesota but by the end of June, prices had returned to a more normal level. Similar price increases occurred in 2012 on the West Coast after a series of unplanned outages. While we recognize the burden these price increases place on the American public, these occurrences are relatively short-lived and are the result of largely unforeseeable circumstances.

EIA remains actively engaged in monitoring and reporting on matters related to domestic petroleum product supplies. EIA collects, analyzes, and reports more data on our national petroleum supply system than any other comparable organization in the world. We access data on where crude is produced, what type of crude it is, where it goes, and the ultimate slate of refined products. We collect data on product movements by pipeline and ship and have an extensive database on crude and product imports including the product type and crude quality, the importing entity, and the country (and port) of origin. Like any other organization covering a rapidly changing industry, we also recognize the need for increased data collection and analysis. Over the last several years, EIA has recognized significant changes to the supply and demand patterns for petroleum products both domestically and with external trade. As resources have permitted, and in some cases where significant regional transitions have raised concern with Members of Congress, EIA has monitored, analyzed and reported on potential market changes, including the following:

- U.S. exports of petroleum products
- The proposed sale or closure of three East Coast refineries
- West Coast refinery outages and gasoline price increases
- Possible closure of the Tesoro refinery in Hawaii
- Closure of the Hess Port Reading, NJ refinery
- Midwest refinery outages and gasoline price increases

We have been developing a system to collect crude production data at the well head to better monitor and project domestic crude production. EIA is monitoring the following emerging trends in transportation and midstream infrastructure: crude shipments by rail, barge and truck (see Attachment 1 July 11 This Week in Petroleum article), crude oil pipeline capacity additions and reversals, repurposing of natural gas pipelines to crude oil and gas liquids service, changing availability of coastwise

compliant and foreign flag vessels. We regularly publish a variety of reports on important petroleum supply trends, including This Week In Petroleum, the Short Term Energy Outlook and the Annual Energy Outlook. Although EIA has followed Atlantic basin petroleum product trade for decades, we are currently challenged to keep up with the expanding products trade within the Americas and across the Pacific. This Committee is a very important customer of the EIA and I would look forward to a discussion with you.

Thank you for the opportunity to testify before the Committee.

This Week In Petroleum

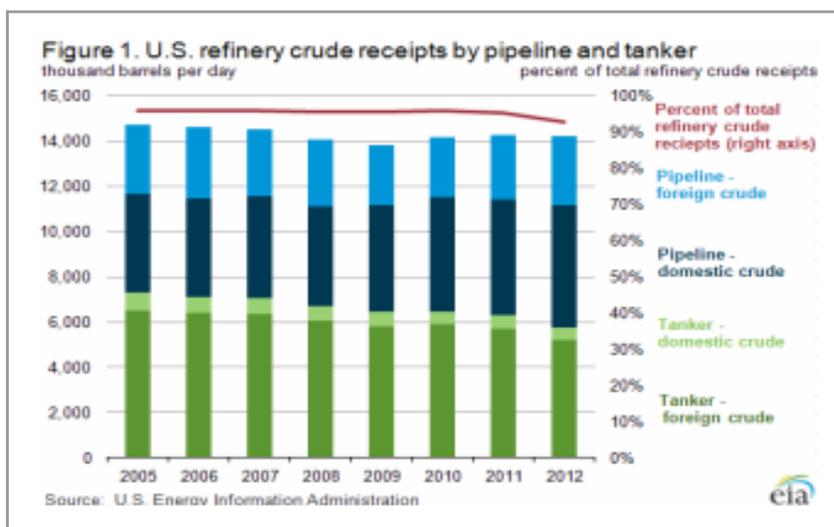
Released: July 11, 2013
Next Release: July 17, 2013

U.S. crude oil increasingly moves by barge, truck and rail

The U.S. Energy Information Administration (EIA) recently released its annual data series tracking how crude oil reaches the refinery gate. Not surprisingly, the 2012 data show heightened reliance on crude receipts via barge, truck and rail.

There has been much discussion about the rise in [U.S. crude oil production](#) and the resulting overhang in inventories at Cushing, Oklahoma and elsewhere in the midcontinent because of pipeline infrastructure that has not kept pace with burgeoning domestic crude oil supply. The supply-pipeline mismatch is encouraging market participants to increasingly rely on alternative transportation options.

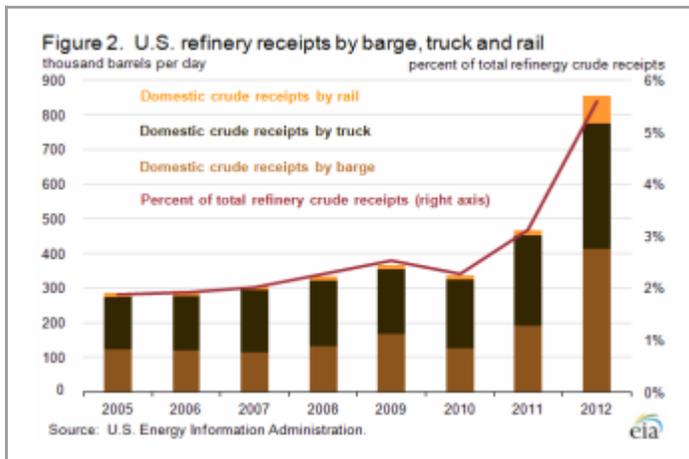
From 2005 to 2010, 96 percent of refinery crude oil receipts came by pipeline and tanker (ship). With relatively low costs and high capacity, pipelines have long been the delivery method of choice for inland refineries. Coastal refineries, on the other hand, have typically been served by tankers of waterborne imports or offshore production. In 2011, this usage began to decline, and in 2012, pipelines and tankers delivered 93 percent of crude oil processed by U.S. refiners (Figure 1). The balance is made up primarily of domestic crude supplies carried via barge, rail and truck. Foreign receipts via barge have declined slightly.



Attachment 1

Because truck and rail are less cost-effective options for moving crude, they typically have accounted for a very small portion of refinery crude receipts, averaging just 1 percent of total receipts from 2000 to 2010. Starting in 2011, this truck and rail volume increased, and in 2012 it represented 3 percent of refinery receipts. Additionally, domestic barge receipts also increased, and now account for close to 3 percent (Figure 2). Expanding existing pipelines or building entirely new ones is costly and requires lengthy regulatory review. Using trucks and trains on the other hand, provides greater flexibility and uses existing infrastructure. As long as the Bakken and WTI prices trade at a large enough discount to global, waterborne crudes, these transportation patterns are likely to persist or even expand.

EIA collects data on crude delivery methods annually from all U.S. refineries. In cases where multiple transportation modes are used, respondents report the mode used for the last 100 miles. If several modes are used, and none is more than 100 miles, the method representing the longest distance is recorded. This may partially explain the increase in domestic barge traffic, with crude oil loaded on rail cars at production areas and then transferred to barges for the final leg of some journeys to refineries, particularly on the East Coast and along the Mississippi River. With increased rail traffic reported by the [Association of American Railroads](#) for the first half of 2013, it is likely that the EIA data on domestic crude receipts by rail will be higher in EIA's 2013 survey.



In addition to delivering more crude oil to U.S. refineries, railroads are shipping U.S. crude oil to [eastern Canadian refineries](#). While the Midwest has been the traditional source for U.S. crude oil exports to Canada, a recent increase in exports is being led by deliveries from the Gulf Coast (waterborne) and the East Coast. The exports from the East Coast are primarily barrels that moved east from North Dakota's Bakken region by rail and are then exported through New York state. Small amounts of Canadian crude are also starting to move by rail to U.S. refineries, with 2011 marking the first time in 10 years that foreign-sourced rail shipments were reported. At nearly 1,000 barrels per day (bbl/d), this was the highest volume of foreign oil-by-rail recorded since EIA started

Attachment 1

publishing these data in 1981. In 2012 that number set a new record of more than 11,000 bbl/d.

Gasoline price decreases while diesel fuel increases

The U.S. average retail price of regular gasoline decreased less than a penny to \$3.49 per gallon as of July 8, 2013, up eight cents from last year at this time. The Midwest price increased two cents to \$3.41 per gallon, while prices in all other regions decreased. The largest decrease came in the Rocky Mountain region, where the price is \$3.61 per gallon, down three cents from last week. The Gulf and West Coast prices both decreased two cents, to \$3.30 and \$3.88 per gallon, respectively. Rounding out the regions, the East Coast price is down one cent to \$3.46 per gallon.

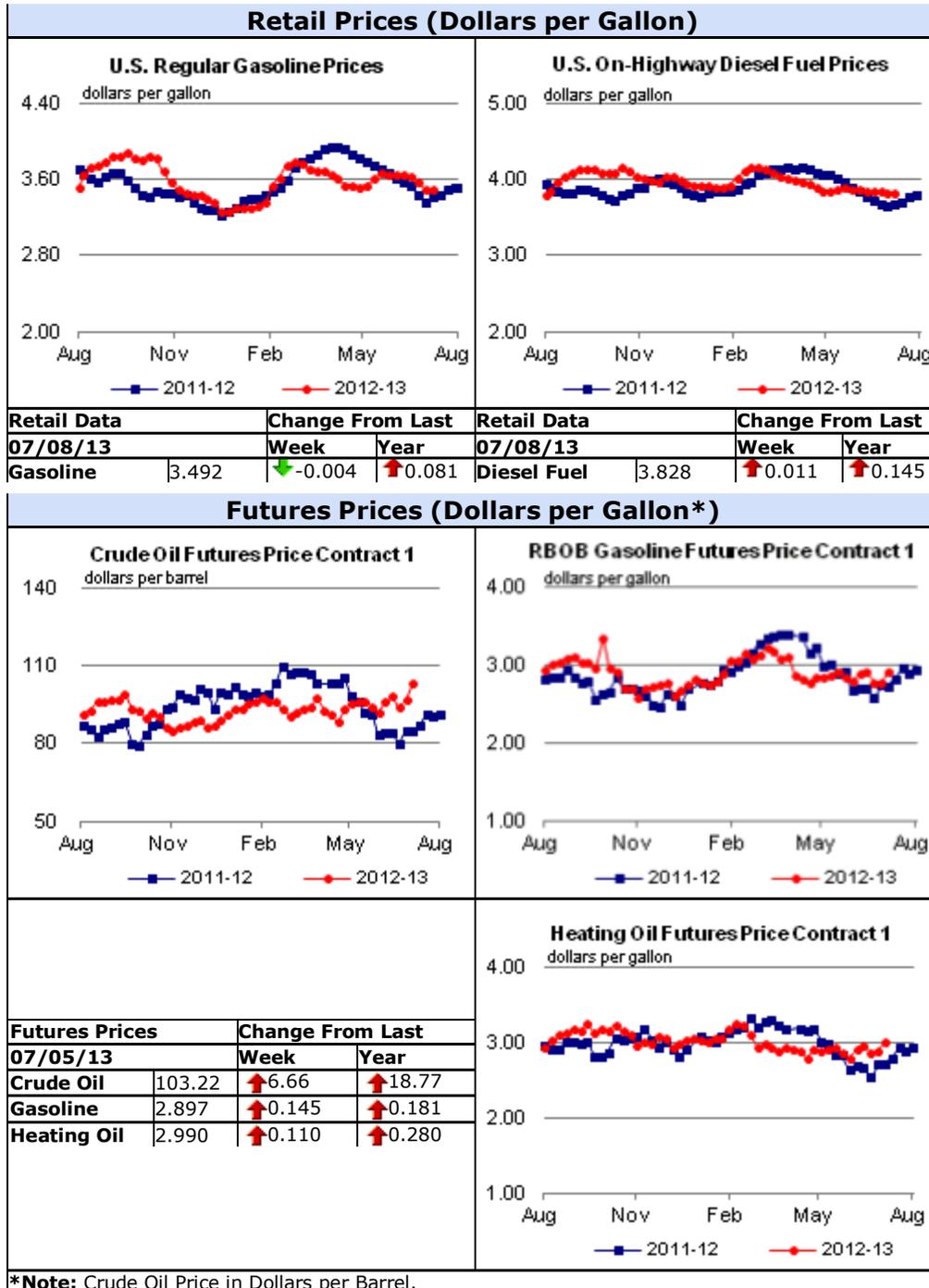
The national average diesel fuel price increased one cent to \$3.83 per gallon, 15 cents higher than last year at this time. The Rocky Mountain price decreased one cent to \$3.81 per gallon, while prices in all other regions increased. The largest increase came on the Gulf Coast, where the price is up two cents to \$3.75 per gallon. The East Coast, Midwest, and West Coast prices all increased a penny, to \$3.83, \$3.82, and \$3.95 per gallon, respectively.

Propane inventories gain

Total U.S. inventories of propane increased 1.0 million barrels from last week to end at 57.4 million barrels, but are 5.8 million barrels (9.2 percent) lower than the same period a year ago. The Gulf Coast region led the gain with 1.0 million barrels, while East Coast stocks increased by 0.2 million barrels. Midwest stocks increased by 0.1 million barrels and Rocky Mountain/West Coast stocks decreased by 0.3 million barrels. Propylene non-fuel-use inventories represented 5.3 percent of total propane inventories.

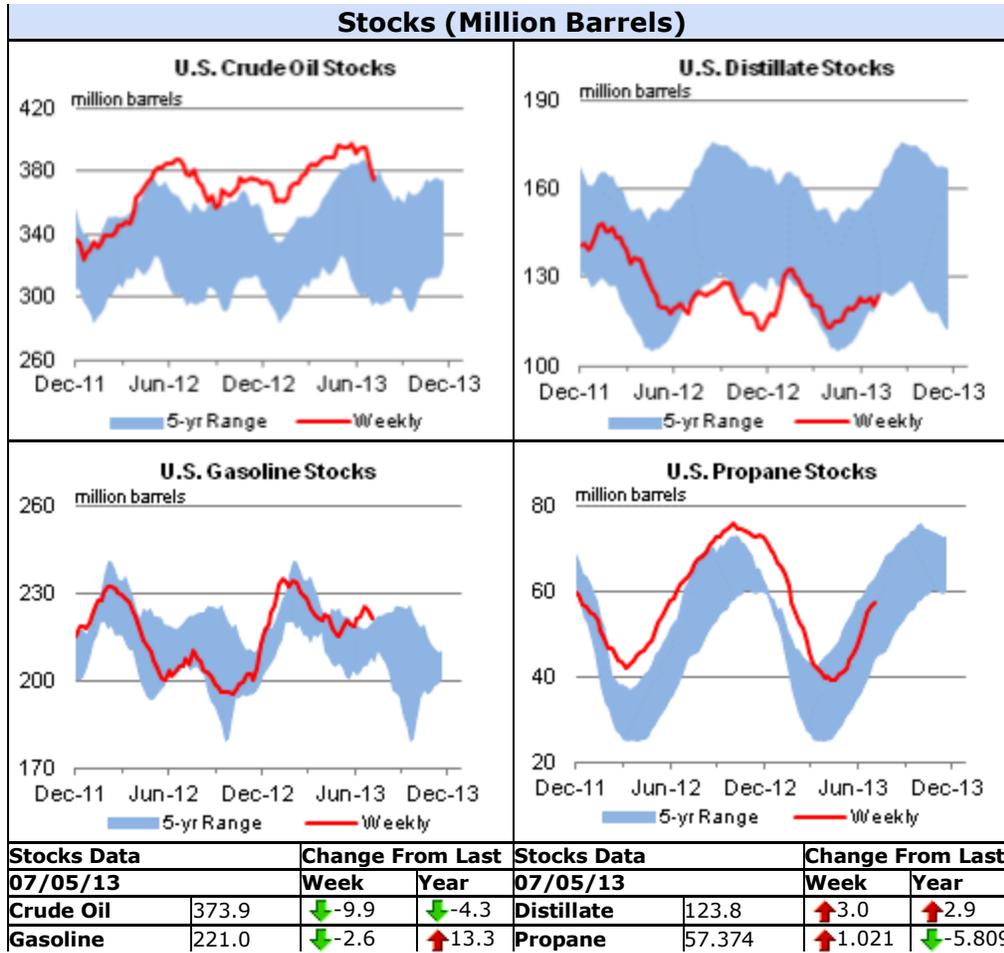
Text from the [previous editions](#) of *This Week In Petroleum* is accessible through a link at the top right-hand corner of this page.

Attachment 1



*Note: Crude Oil Price in Dollars per Barrel.

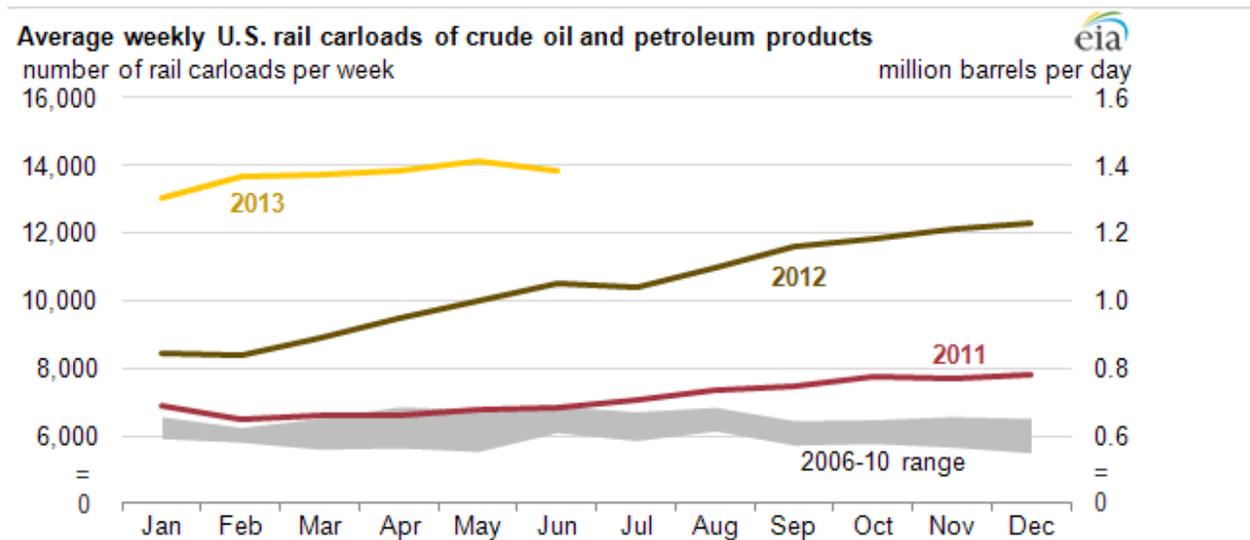
Attachment 1



TODAY IN ENERGY

JULY 10, 2013

Rail delivery of U.S. oil and petroleum products continues to increase, but pace slows



Source: U.S. Energy Information Administration, based on Association of American Railroads.

Note: Petroleum product rail shipments do not include ethanol. Conversion of rail carloads per week into million barrels per day includes assumption of 700 barrels per rail carload.

With U.S. [crude oil production](#) at the highest level in two decades, outstripping pipeline capacity, the United States is relying more on railroads to move its new crude oil to refineries and storage centers. The amount of crude oil and refined petroleum products transported by rail totaled close to 356,000 carloads during the first half of 2013, up 48% from the same period in 2012, according to [Association of American Railroads](#) (AAR).

U.S. weekly carloadings of crude oil and petroleum products averaged nearly 13,700 rail tankers during the January-June 2013 period. With one rail carload holding about 700 barrels, the amount of crude oil and petroleum products shipped by rail was equal to 1.37 million barrels per day during the first half of 2013, up from 927,000 barrels per day during the first six months of last year. AAR data do not differentiate between crude oil and petroleum products, but it is generally believed that most of the volume being moved in the 2006-10 period was petroleum products and most of the increase since

Attachment 2

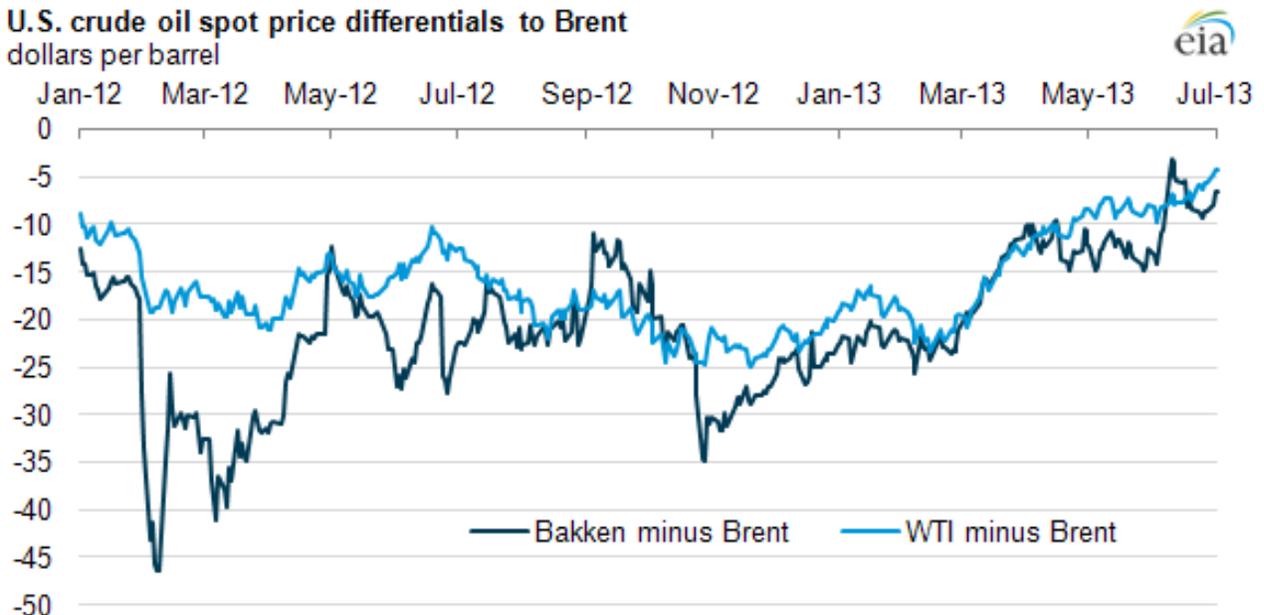
then has been crude oil. Crude oil accounts for about half of those 2013 daily volumes, according to AAR.

The roughly 700,000 barrels per day of crude oil, which includes both imported and domestic crude oil, moved by rail compares with the 7.2 million barrels of crude oil the United States produces daily, based on the latest 2013 monthly [output numbers](#) from the U.S. Energy Information Administration.

The jump in crude oil production from [North Dakota](#), where there is not enough pipeline capacity to move supplies, accounts for a large share of the increased deliveries of oil by rail. North Dakota is the second largest oil producing state after Texas, as advanced drilling technology has unlocked millions of barrels of tight oil in the [Bakken Shale](#) formation.

More Bakken crude oil moving to market by rail has helped narrow the difference between the spot prices for Bakken crude oil and international benchmark Brent crude oil in recent months to its smallest gap—less than \$5 per barrel—in more than one-and-half years. The narrower spread reduces the incentive to ship oil to coastal refineries. This development, along with the lack of railcars (some estimates cite a 60,000 car backlog) may explain the slower growth shown in 2013 carload data.

U.S. crude oil spot price differentials to Brent
dollars per barrel



Source: U.S. Energy Information Administration, based on Bloomberg.

Note: The chart above uses Dated Brent for comparison among the crude oil prices. Dated Brent is a market term for a cargo of North Sea Brent blend crude oil that has been assigned a date when it will be loaded onto a tanker.

tags: [Bakken](#) , [Brent](#) , [Liquid Fuels](#) , [Oil/Petroleum](#) , [Rail](#)

Moving Crude Oil by Rail

ASSOCIATION OF AMERICAN RAILROADS

DECEMBER 2013

Summary

Technological advances, along with relatively high crude oil prices, have led to sharply higher U.S. crude oil production. Historically, most crude oil has moved from production areas to refineries by pipeline. However, much of the recent increases in crude oil output has moved by rail. In 2008, U.S. Class I railroads originated just 9,500 carloads of crude oil. In 2012, they originated nearly 234,000 carloads and will likely originate around 400,000 carloads in 2013.

Railroads have an excellent safety record regarding crude oil transportation — better, in fact, than pipelines in recent years. Based on U.S. DOT data, the crude oil “spill rate” for railroads from 2002-2012 was an estimated 2.2 gallons per million ton-miles, compared with an estimated 6.3 for pipelines. Railroads are continuously striving to further improve the safety of moving crude oil by rail. For example, the rail industry recently urged federal regulators to toughen existing standards for new tank cars and require that the approximately 92,000 existing tank cars used to transport flammable liquids, including crude oil, be retrofitted with advanced safety-enhancing technologies or, if not upgraded, phased out.

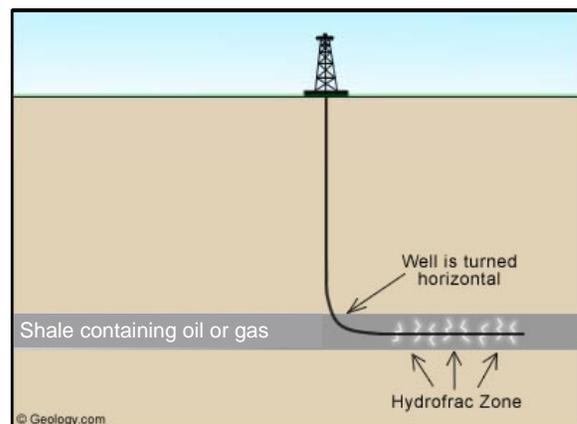
Beyond providing transportation capacity, railroads offer energy market participants the ability to shift deliveries quickly to different markets, enabling producers to sell their product to the market offering the best price. Additional pipelines will probably be built in the years ahead, but the competitive advantages railroads offer will keep them in the crude oil transportation market long into the future.

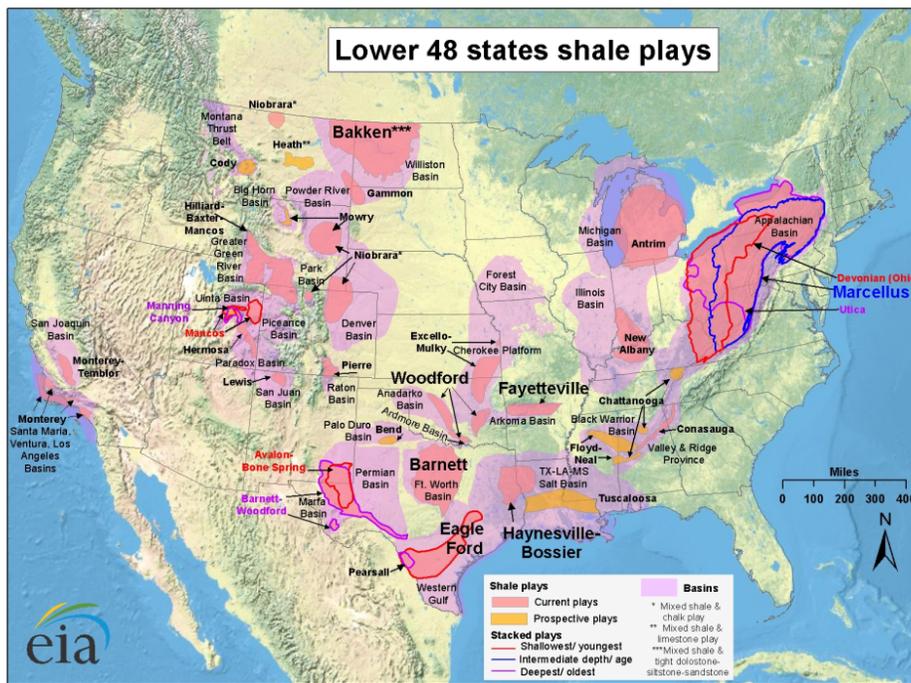
The Shale Revolution

Throughout the world, huge quantities of crude oil and natural gas are trapped in non-permeable shale rock. Over the past few years, technological advances — especially in hydraulic fracturing and horizontal drilling — along with higher crude oil prices have made recovery of much of this oil and gas economically feasible.

Hydraulic fracturing, or “fracking,” involves pumping a mixture of water, sand and chemicals down a well at high pressure to create thin cracks in the shale rock, thereby freeing oil and gas trapped inside and allowing it to be brought to the surface.

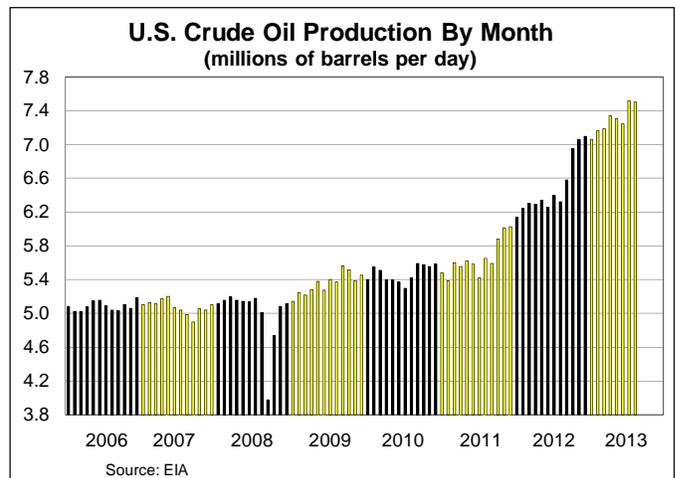
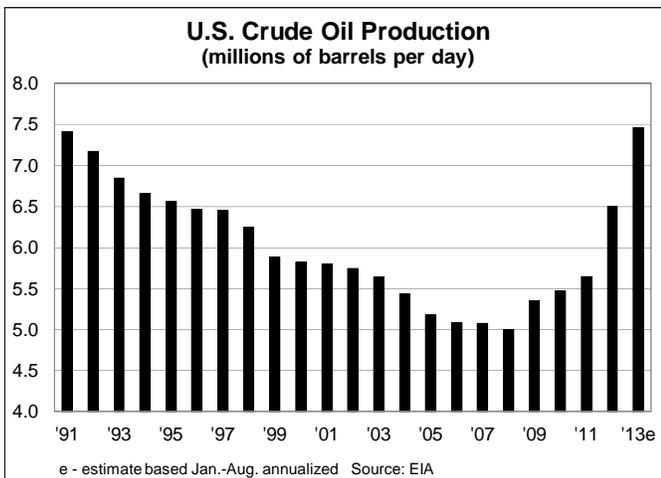
Horizontal drilling involves creating an initial vertical bore of up to several thousand feet, then turning the drill and continuing horizontally for up to several miles.



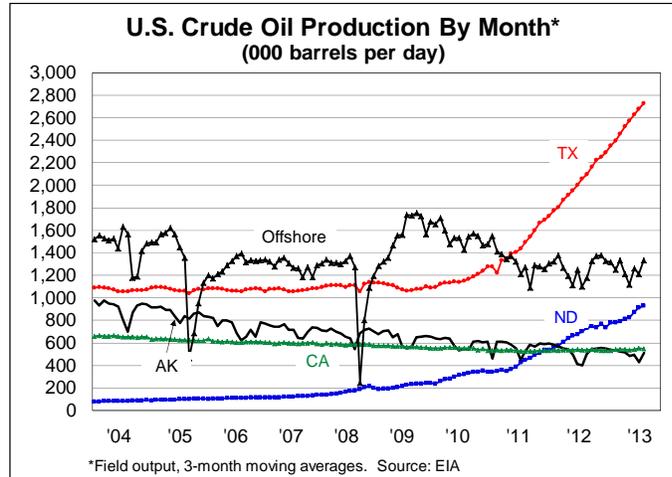


The map above shows the distribution of U.S. shale deposits. To date, the most important are Bakken in North Dakota and Montana; Barnett in Texas; and Marcellus in the east, especially in Pennsylvania and Ohio. Other key shale areas include Niobrara in Wyoming and Colorado, and Eagle Ford and Permian in Texas. Some areas contain more natural gas than crude oil; others contain more oil than natural gas. There are still many unknowns — including the long-term productivity of shale wells and the extent to which environmental concerns will limit fracking in the future — but it's clear that, thanks to shale, economically recoverable U.S. gas and oil reserves are far higher than they were thought to be just a few years ago.

U.S. crude oil production peaked in 1970 at 9.6 million barrels per day, and by 2008 it had fallen to 5.0 million barrels per day as new production failed to keep pace with depletion of older fields. By 2012, though, U.S. crude oil production had risen to an average of 6.5 million barrels per day. Since November 2012, production has exceeded 7 million barrels per day — the first time that's happened since 1992 — and by the summer of 2013 was 7.5 million per day.

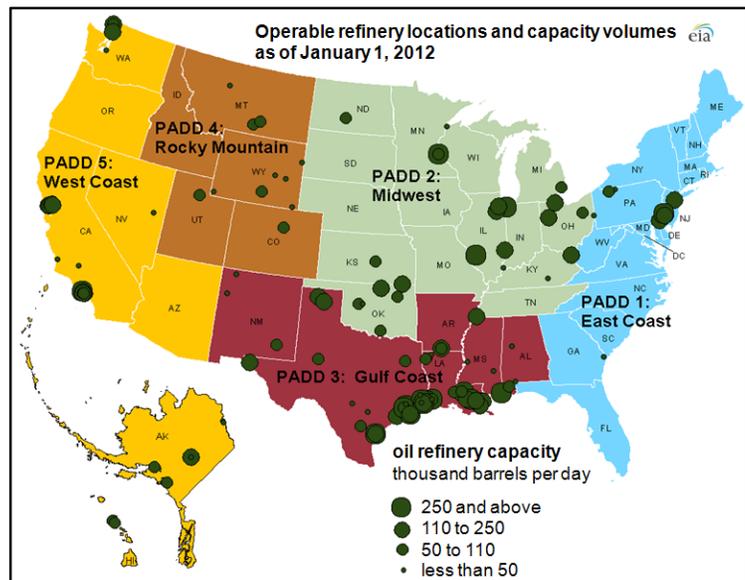


Much of the recent increase in crude oil production has been in North Dakota, home to the Bakken Shale formation. Crude oil production in North Dakota rose from an average of 81,000 barrels per day in 2003 to around 900,000 barrels per day by mid-2013, making North Dakota the second-largest oil producing state. Crude oil output in Texas, the top producer, was relatively flat from 2003 to 2009, but has skyrocketed since then, exceeding 2.6 million barrels per day by mid-2013. Output in California and Alaska has been trending down for years.



Transporting Crude Oil by Rail

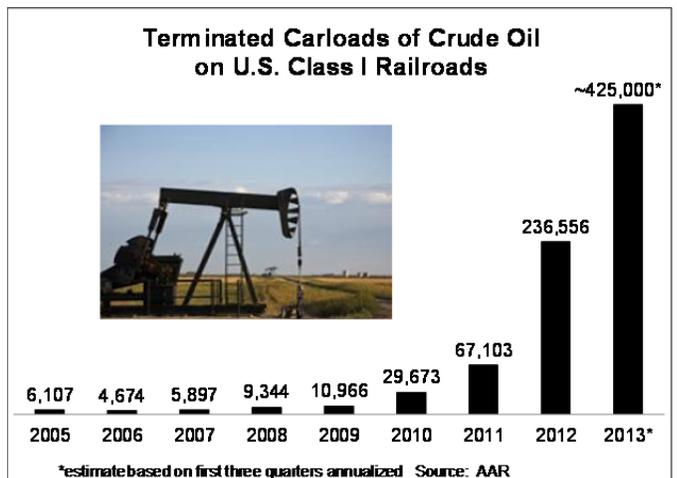
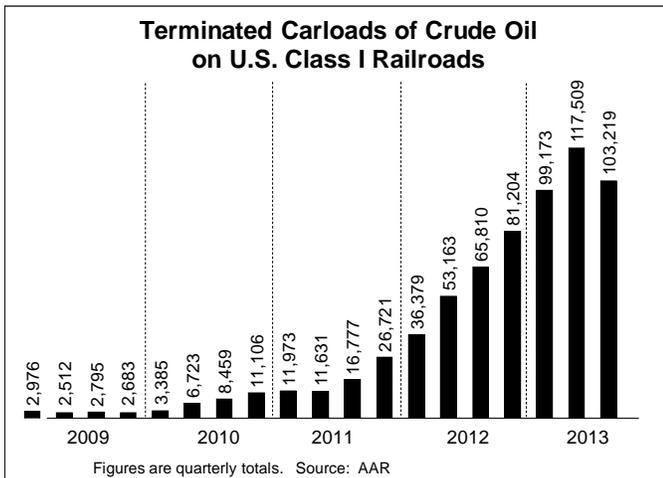
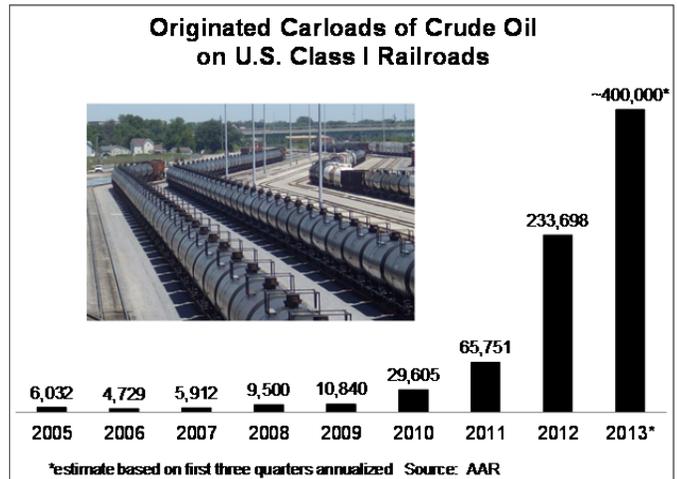
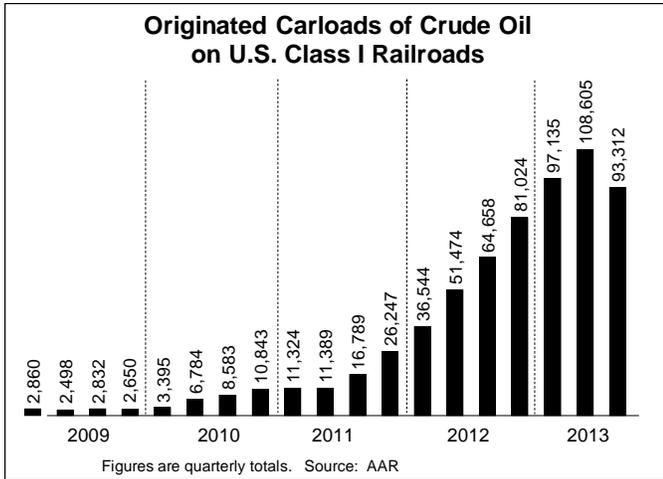
Crude oil has little value unless it can be transported to refineries, but most U.S. refineries are located in traditional crude oil production areas (Texas, Oklahoma) or on the coasts where crude oil transported by tanker is readily accessible (California, Washington, New England, Gulf of Mexico), rather than near up-and-coming crude oil production areas like North Dakota (see nearby map). In part because of the long, rigorous process required to obtain the necessary permits to build new refineries, it's basically impossible for refineries to come on line quickly near the new production areas.



Historically, most crude oil has been transported via pipelines. However, in places like North Dakota that have seen huge increases in crude oil production, the existing pipeline network lacks the capacity to handle the higher production. Pipelines also lack the flexibility and geographic reach to serve many potential markets. Railroads, though, have the capacity and flexibility to fill this gap.

Small amounts of crude oil have long been transported by rail, but since 2009 the increase in rail crude oil movements has been enormous. As recently as 2008, U.S. Class I railroads (including the U.S. Class I subsidiaries of Canadian railroads) originated just 9,500 carloads of crude oil. By 2011, carloads originated were up to nearly 66,000, and in 2012 they surged to nearly 234,000. In the first three quarters of 2013, Class I railroads originated 299,652 carloads of crude oil, 96 percent higher than the 152,676 carloads originated in the first three quarters of 2012. Based on the first nine months of the year, crude oil originations in 2013 will probably total around 400,000 carloads. Crude oil accounted for 1.4 percent of total Class I originated carloads in 2013 through September, up from just 0.03 percent in 2008.

The vast majority of crude oil moving by rail in the United States both originates and terminates on U.S. Class I railroads, so the number of carloads originated by Class I carriers (see top charts below) is always close to the number of carloads terminated by Class I carriers (see bottom charts below). However, some crude oil that originates on U.S. Class I railroads might be delivered to U.S. short lines or to railroads in Canada for termination. These carloads would be included in the top charts, but not in the bottom charts. In addition, some crude oil that terminates on U.S. Class I railroads might originate on railroads in Canada or on U.S. short line railroads. These carloads would be included in the bottom charts, but not in the top charts.



Assuming, for simplicity, that each rail tank car holds about 30,000 gallons (714 barrels) of crude oil, the 299,652 carloads of crude oil originated in the first three quarters of 2013 equal approximately 784,000 barrels per day moving by rail. As a point of reference, according to EIA data, total U.S. domestic crude oil production in the first three quarters of 2013 was approximately 7.3 million barrels per day, so the rail share was around 11 percent — up from a negligible percentage a few years ago.

Barring unforeseen circumstances, deposits of oil and gas in shale formations all over the country will be developed. In recent years, though, North Dakota, and the Bakken region more generally, have accounted for the vast majority of new rail crude oil originations. According to

estimates from the North Dakota Pipeline Authority, as of mid-2013, approximately 640,000 barrels per day of crude oil were moving out of North Dakota by rail, equivalent to more than 60 percent of North Dakota's crude oil production.

Advantages of Transporting Crude Oil by Rail

Historically, pipelines have been the dominant mode for transporting crude oil long distances. That's still the case, but railroads have become critical players in crude oil transportation. In addition to the critical fact that railroads provide transportation capacity in many areas where pipeline capacity is insufficient, railroads offer a number of other advantages for transporting crude oil:

- **Geographical Flexibility.** By serving almost every refinery in the United States and Canada, railroads offer market participants enormous flexibility to shift product quickly to different places in response to market needs and price opportunities. Railroads deliver crude oil to terminals not only in Louisiana and other places in the Gulf region, but also to locations on the East Coast, the West Coast, and elsewhere.
- **Responsiveness.** Rail facilities can almost always be built or expanded much more quickly than pipelines and refineries can be. Essentially, railroads are the only transportation mode that can invest in facilities quickly enough to keep up with production growth in the emerging oil fields.

- **Efficiency.** As new rail facilities are developed, railroads are involved every step of the way. For example, at origin and destination sites, railroad economic development and operations teams help facility owners decide where to locate assets and how to lay out rail infrastructure on the site to maximize efficiency.

Railroads also help crude oil customers find ways to load and unload tank cars more quickly and reduce en-route delays. Promoting unit train shipments is often a key part of this process. Unit trains are long trains (usually at least 50 and sometimes 120 or more cars) consisting of a single commodity. These trains use dedicated equipment and generally follow direct shipping routes to and from facilities designed to load and unload them efficiently — say, from a gathering location near oil production areas to an unloading terminal at or near a refinery — and generally have much lower costs per unit shipped than non-unit trains. A single large unit train might carry 85,000 barrels of oil and be loaded or unloaded in 24 hours.

- **Underlying Infrastructure.** Over the past few years, railroads have invested hundreds of millions of dollars to replace and resurface tracks, buy new locomotives, build new



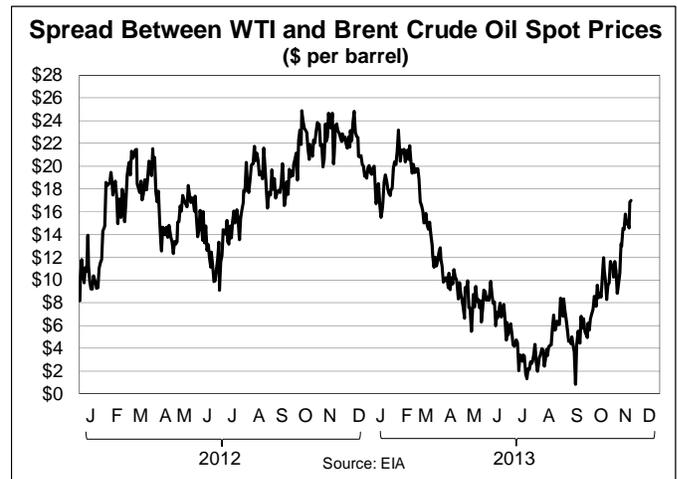
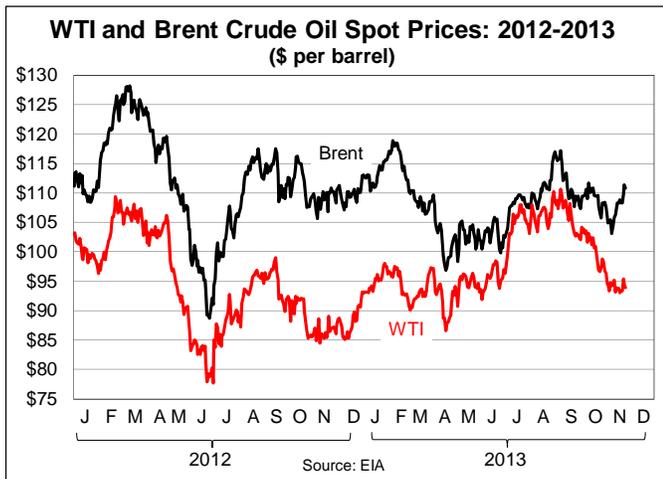
terminals and track capacity, hire new employees, and take other steps to enhance their ability to transport crude oil. Rail investments related to crude oil service are just a small part of a much larger set of ongoing rail investments. In recent years, U.S. freight railroads have been reinvesting more than ever before, including a record \$25.5 billion in 2012, to create and maintain a freight rail network that is second to none in the world.

- **Product Purity.** The composition of crude oil varies from region to region, even from well to well within a region. Consumers of crude oil often desire a specific type of crude oil. Shipping crude by rail allows “pure barrels” to be delivered to destination in ways that are not always possible with pipelines.

Crude oil producers and other market participants have made huge investments in both the infrastructure and the tank cars needed to move crude by rail, signaling confidence in the long-term viability of rail service in this market. Even as more pipelines are built or expanded, railroads will continue to provide a set of advantages — especially flexibility — that will enable them to continue to play a key role in the petroleum-related market long into the future.

Brent vs. WTI

The crude oil market is extremely complex, with lots of moving pieces and different players pursuing different goals. That said, in the case of crude oil — as in the case of every commodity that railroads haul — railroads face a variety of competitive constraints and market factors that, together with rail rate and service levels, collectively determine traffic levels.



One such factor involves crude oil prices. The chart above left shows the West Texas Intermediate (WTI) and Brent spot oil prices since January 2012. The chart above right shows the “spread” between the two. Historically, the spread typically has been just a few dollars, but over the past couple of years it’s been as high as \$28, thanks to a surge in U.S. oil production that caused a glut of crude oil inventories at Cushing, Oklahoma, where WTI is priced. The spread narrowed considerably in the third quarter of 2013. This narrowing — in addition to pipeline expansions in some areas — made some crude by rail movements (especially in Texas) less competitive compared to pipelines and resulted in a decline in crude by rail movements in the third quarter of 2013 compared with the second quarter of 2013. Clearly, in the months ahead, Brent-WTI spread will continue to play a key role in crude oil markets and, therefore, in crude by rail.

Moving Crude Oil Safely

Railroads have an excellent crude oil safety record — better, in fact, than pipelines in recent years. Based on data from the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration, the “spill rate” for U.S. railroads from 2002-2012 was an estimated 2.2 gallons per million crude oil ton-miles generated. The comparable spill rate for pipelines is nearly three times the rail rate at approximately 6.3 gallons per million ton-miles.

Pipelines carry —and spill — much more crude oil than railroads do. From 2002-2012, an estimated 19.9 million gallons (474,000 barrels) of crude oil were spilled in pipeline incidents, compared with an estimated 95,000 gallons (2,300 barrels) of crude oil spilled in rail incidents over the same period. The rail figure is less than 1 percent of the pipeline figure.

From 2002-2012, there were 148 incidents involving releases of crude oil from railroads, of which 109 involved releases of less than five gallons. Railroads are required to report spills of any size, including very small spills. By contrast, in most cases pipelines only have to report spills of at least five gallons. Just 39 of the 148 railroad incidents had releases of more than five gallons. By contrast, pipelines reported 1,785 spills of at least five gallons from 2002-2012, more than 45 times the number of rail incidents.

	Number of Incidents		Total Gallons Spilled	Total Barrels Spilled	Estimated Spill Rate*
	< 5 gallons spilled	> 5 gallons spilled			
Railroads	148	39	95,000	2,300	2.2
Pipelines	unknown	1,785	19.9 million	474,000	6.3

*Gross gallons spilled per million ton-miles generated Numbers for 2012 are preliminary.
Source: AAR based on data from the Pipeline and Hazardous Materials Safety Administration

The bottom line, though, is that both railroads and pipelines are safe, reliable ways to transport crude oil. Each enhances our energy security and benefits consumers.

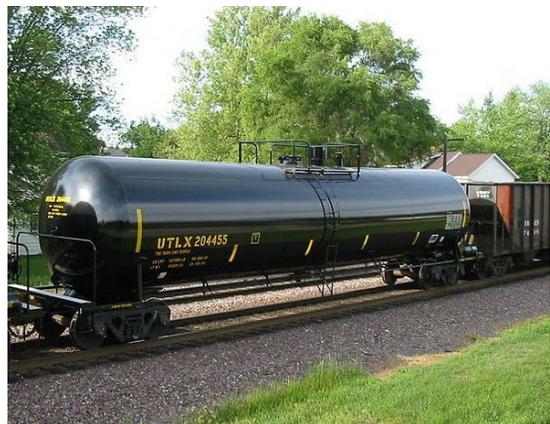
Enhancing Tank Car Safety

Crude oil is transported by railroads in tank cars. The North American tank car fleet consists of about 335,000 cars. Railroads themselves own less than 1 percent of these cars; the vast majority are owned by rail customers and leasing companies.

Thousands of different commodities are carried in tank cars. Of the 335,000 tank cars in the North American fleet, around 92,000 are used to transport crude oil and other flammable liquids. A typical carload of crude oil contains around 30,000 gallons.

In the United States, federal regulations pertaining to tank cars are set by the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA). Transport Canada (TC) performs a similar role in Canada.

Meanwhile, the AAR Tank Car Committee sets industry standards regarding how tank cars used in North America are designed and constructed that are above and beyond federal



standards. The tank car committee is comprised of the AAR, rail car owners, manufacturers, and rail hazmat customers, with active participation from the U.S. DOT, Transport Canada, and the National Transportation Safety Board (NTSB).

The rail industry has been aggressive in finding ways to improve the safety of crude oil transport. For example, in March 2011, the tank car committee petitioned PHMSA to adopt more stringent requirements for new tank cars used to transport certain types of hazardous materials, including crude oil. These tougher standards called for a thicker, more puncture resistant tank car shell; extra protective “head shields” at both ends of tank cars; and additional protection for the fittings on the top of a car that enable access to the inside of the car.

In July 2011, after it had become clear that PHMSA approval of the committee’s proposal was not imminent, the committee adopted what it had proposed to PHMSA as the basis for new industry standards for tank cars used to carry ethanol or crude oil. The new standards apply to new tank cars ordered after October 1, 2011. To date, some 14,000 tanks cars have been built to this tougher standard.



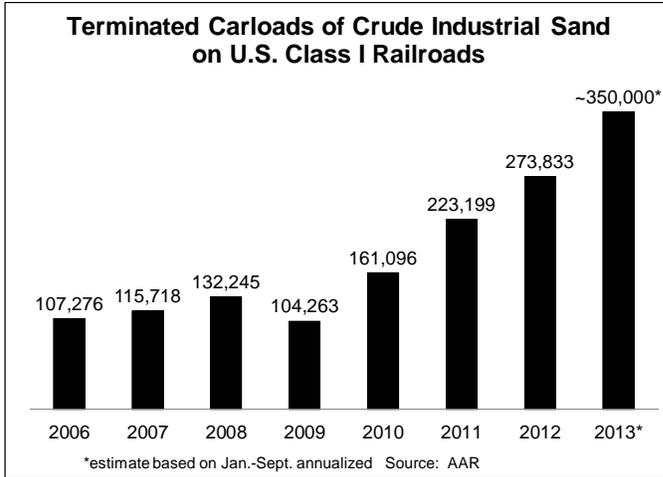
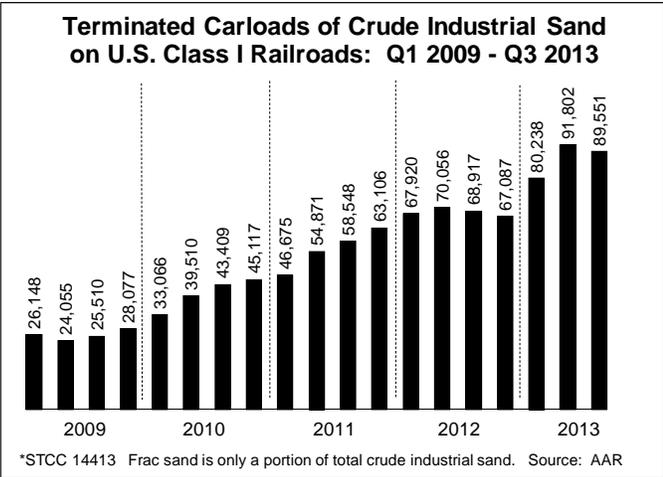
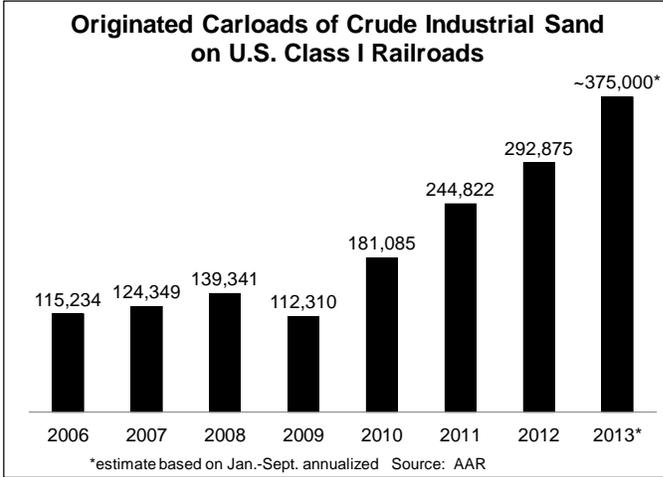
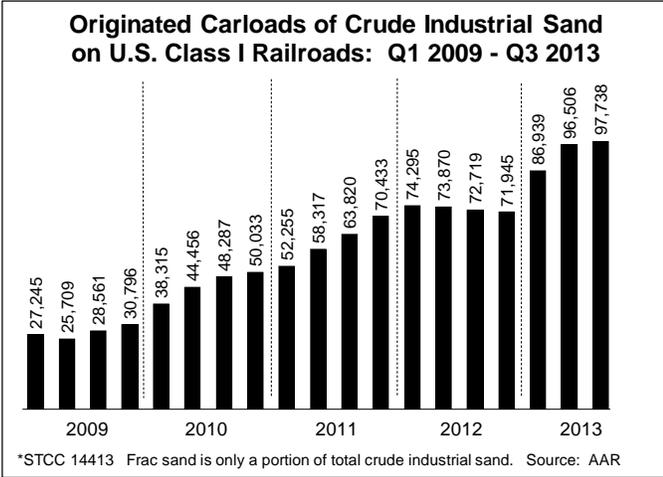
More recently, in November 2013, the rail industry called on PHMSA to require the 92,000 tank cars used to transport flammable liquids, including crude oil, to be retrofitted with enhanced safety features or, if no upgrades are made, aggressively phased out. These retrofits would substantially reduce the likelihood of a release of potentially dangerous products if affected tank cars are involved in accidents. Railroads will continue to work with PHMSA, their customers, tank car builders, and others to ensure that tank car safety continues to improve.

Frac Sand and Other Petroleum-Related Commodities

In addition to moving crude oil, railroads also transport large amounts of “frac sand” to crude oil and natural gas producers. A single horizontal well typically uses between 3,000 and 10,000 tons of sand. A typical rail car of frac sand contains around 100 tons.

Sand is used in many different industrial and construction applications, of which hydraulic fracturing is just one. Data on rail shipments of frac sand alone are not available, but data on rail shipments of industrial sand in total are. In 2009, U.S. Class I railroads (including the U.S. subsidiaries of Canadian railroads) originated just over 112,000 carloads of industrial sand. In 2012, Class I railroads originated nearly 293,000 carloads of sand and are on track to originate approximately 375,000 carloads in 2013. While it’s not possible to determine precise percentages, frac sand is almost certainly the primary driver behind the increased industrial sand movements on railroads over the past few years.

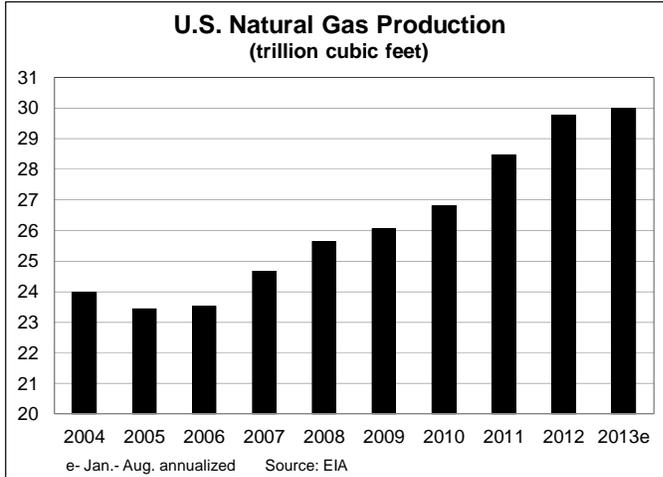
A number of short line and regional freight railroads also carry frac sand; their movements are not included in the charts on the next page. Railroads are also key players in the movement of iron ore, scrap steel, and other raw materials to steel plants that produce the pipes used in crude oil and natural gas production, and in the delivery of those pipes from steel plants to crude oil and natural gas production areas.



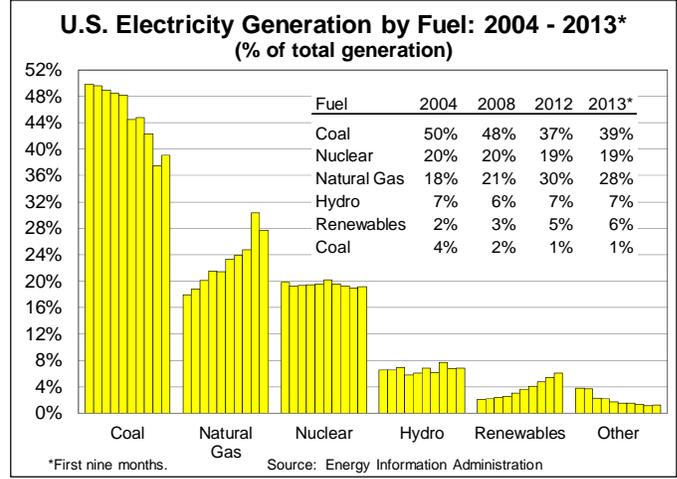
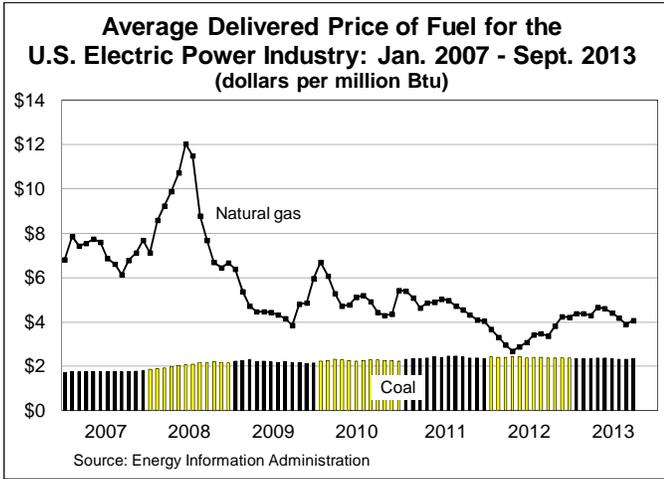
The Shale Revolution and Coal

The “shale revolution” has led to higher U.S. rail carloads of crude oil and frac sand, but it’s also led to sharply lower rail carloads of coal. Fracking and horizontal drilling have led to sharply higher U.S. natural gas production (see the chart at right), which in turn has meant sharply lower natural gas prices to utilities (see the chart on the top left of the next page). This has made electricity generated from natural gas more competitive in the electricity marketplace relative to electricity generated from coal.

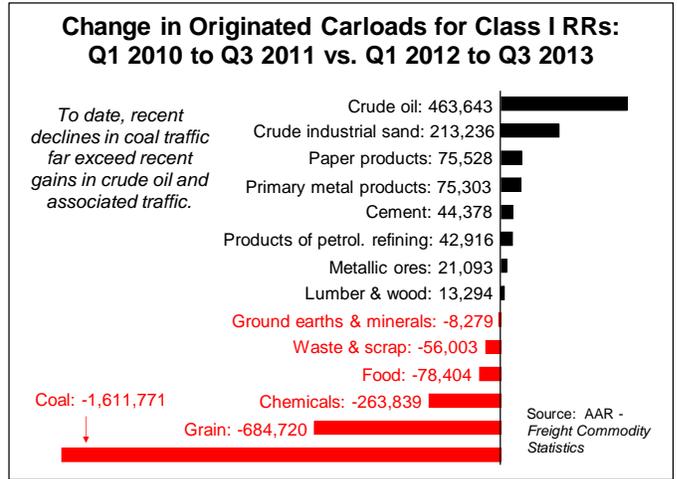
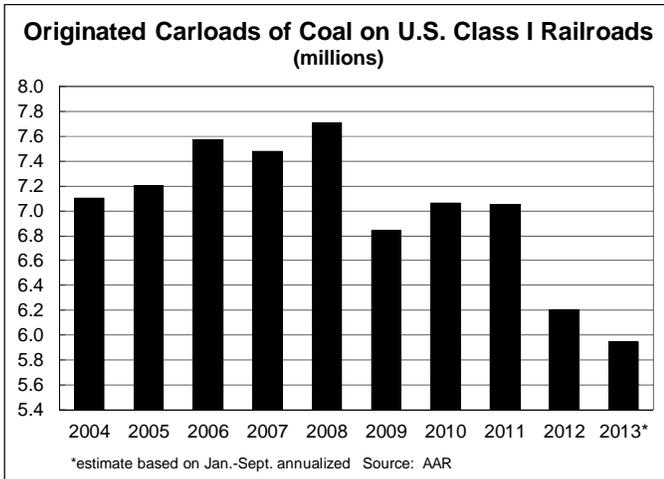
Consequently, natural gas’s share of total U.S. electricity generation has surged in recent years to record highs, while electricity generated from coal has fallen correspondingly. The coal share of electricity generation was 50 percent or higher each year from 1980 through 2003 and 48 percent as recently as 2008, but was down to 37 percent in 2012 before rising a bit in



2013 (see the chart below right). The growth of renewable energy and increasingly stringent environmental constraints have also played roles in coal's declining share of electricity generation.



Reduced electricity generation from coal has meant a big decline in rail carloads of coal. U.S. Class I railroads originated 6.2 million coal carloads in 2012, the lowest annual total since 1993. Coal carloads could dip below 6 million in 2013 (see the chart below left). Over the past few years, the decline in coal carloads has far exceeded the increase in carloads of crude oil and frac sand for U.S. railroads (see the chart below right).



Conclusion

The United States is experiencing an unprecedented boom in oil and natural gas production, with most of the increase coming from dense shale rock formations. Among other things, this means North America is likely to move closer to energy self-sufficiency. U.S. freight railroads are playing a critical role. Rail shipments of crude oil have skyrocketed in recent years due to the flexibility and other advantages that moving crude oil by rail offers. Railroads are continually working with energy firms and others to find ways to further improve the safety, reliability, productivity, and cost effectiveness of their service offerings to the energy market.

EMERGING RISKS TASK FORCE REPORT – 2013
Project Overview

Task Force Charter

“The petroleum products moving through the Northwest (NW) are changing in product type, transportation mode and quantity. This task force (TF) will look at those changes and determine how they will impact oil spill risks in the NW. Specific tasks include: (1) Decide how to represent the current and proposed transportation risk picture for AOR (Area of Responsibility). Recommend dividing into sub-taskforces (pipeline, rail, marine); (2) Determine characteristics, response strategies and safety for non-traditional products such as: Oil Sands, coal, residual fuel oil, LNG (liquefied natural gas), biodiesel and synthetic fuels.”

This was an information-gathering TF charged to study changing traffic patterns and volumes of oil and other fuels entering and exiting the region. The Task Force’s diverse membership endeavored to capture a high-level snapshot of such activity in the spring/summer of 2013. The information presented ranges in fidelity because some contributors relied upon single Internet searches for their reports whilst others more familiar with the subject matter cited multiple sources for their work. We understand that research based on a single Internet search is always susceptible to error/bias. We further understand that any findings we present can and will likely change. Economic conditions based on supply and demand are unpredictable, certainly those relating to commodities addressed in this report are. For example, the United States’ LNG market has gone full circle. Five years ago there were plans to import LNG. Today we are a country awash in LNG, looking to export the product. Our 2013 picture will look totally different in a year, possibly as soon as the next step of this project, the Vessel Traffic Risk Assessment, is completed. In addition, a year from now ports, refineries and governments will have built, delayed or cancelled projects seen as “on the books” today. In other words, caveat lector.

Sections of this document will be inserted into the 2014 Northwest Area Contingency Plan update.

Washington State Petroleum Association (WSPA) members’ input provided historical details on Group V oil movement in our region. New details will likely arise that will allow future Area Committees to further address these heavier products. Though WSPA’s input was narrow, they made it clear that “ [WSPA] is unable to critique, comment on or verify much of the factual material in the Draft. Therefore, [WSPA’s] participation in this effort should not be construed as adopting or endorsing this Draft or any subsequent Draft unless [WSPA] does so in writing.”

Scott Knutson, Task Force Chair

TABLE OF CONTENTS

- I. FINDINGS: CRUDE OIL
 - A. Transportation picture
 - B. Definition
 - C. Characteristics
 - 1. Oil Sands Products
 - 2. Bakken Crude Oil
 - D. Response strategies
 - E. Safety issues
- II. CONCLUSIONS
- III. RECOMMENDATIONS

- IV. FINDINGS: COAL
 - A. Transportation picture
 - B. Definition
 - C. Characteristics
 - D. Response strategies
 - E. Safety issues
- V. CONCLUSIONS
- VI. RECOMMENDATIONS

- VII. FINDINGS: RESIDUAL FUEL OIL
 - A. Transportation picture
 - B. Definition
 - C. Characteristics
 - D. Response strategies
 - E. Safety issues
- VIII. CONCLUSIONS
- IX. RECOMMENDATIONS

- X. FINDINGS: LIQUID NATURAL GAS (LNG)
 - A. Transportation picture
 - B. Definition
 - C. Characteristics
 - D. Response strategies
 - E. Safety issues
- XI. CONCLUSIONS
- XII. RECOMMENDATIONS

FINAL

XIII. FINDINGS: BIODIESEL

- A. Transportation picture
- B. Definition
- C. Characteristics
- D. Response strategies
- E. Safety issues

XIV. CONCLUSIONS

XV. RECOMMENDATIONS

XVI. FINDINGS: SYNTHETIC FUELS

- A. Transportation picture
- B. Definition
- C. Characteristics
- D. Response strategies
- E. Safety issues

XVII. CONCLUSIONS / XVIII. RECOMMENDATIONS

XIX. OVERALL EMERGING-RISK PICTURE

Recommendation Matrix

I. FINDINGS: CRUDE OIL

A. Transportation picture

The U.S. crude-by-rail industry has expanded rapidly since January 2011 as domestic crude production soared by 1.4 million barrels per day (MBD) over the same period. The growth of crude-by-rail followed pipeline bottlenecks in the Midwest that caused landlocked inland crudes to be discounted by upwards of \$20 per barrel (Bbl) versus coastal destinations. That price discount made shipping oil by rail to the coast a viable proposition in the absence of new pipeline capacity. Crude-rail terminals in the Bakken formation now load over 400 MBD for shipment to coastal markets.

Higher demand for transporting Bakken crude is also proving to be a lifesaver for rail companies, which have experienced a dramatic decline in coal shipment volumes. Demand for rail services from oil companies is so high, in fact, that many companies are being forced to wait up to nine months to lease rail cars.

According to the Association of American Railroads, the number of rail cars hauling crude oil and petroleum products reached close to 241,000 in the first six months of 2012 compared to 174,000 in the first half of 2011.

Burlington Northern Santa Fe (BNSF) has increased capacity in 2012 to enable the railroad to haul one million barrels per day out of the Williston Basin in North Dakota and Montana. This increased capacity will allow the energy industry to continue the record expansion of oil production in the Williston Basin and to ship the new production to markets throughout the U.S. It will also benefit shippers of other commodities, including agricultural products.

Justin Piper of BNSF Railways reported that their system has moved mostly crude oil through their system to date, with only a small percentage being OSP transported to the U.S. (0.65 percent). There was a 300 percent increase in crude transport in 2011-2012, with no accidental releases. In 2012, there were 16 non-accidental releases averaging 3 gallons per release related to shipper related issues.

In 2012, there were 3,632 shipments of light sweet crude to Washington and 1,557 to Oregon (per Alberta Oil Sands Workshop for Washington State Department of Ecology, the Regional Response Team 10 and the Pacific States/British Columbia Oil Spill Task Force). In 2012, BNSF achieved an accident rate of 1.88 per million train miles, a record for their system. Petroleum unit trains normally contain 80-100 tank cars; each car has a 28,000-gallon capacity. Cars are typically owned, maintained and inspected by the transporter and expected to be a 40-year asset. The rail companies

conduct additional inspections when the cars become part of a train. All cars are built to U.S. standards as specified in 49CFR174.

The safety program employed by BNSF has four parts: 1) community training; 2) emergency preparedness; 3) accident prevention and; 4) emergency response. The community training involves either in-person or online training for local emergency responders. Annually 3-5,000 people are trained nationwide. The emergency preparedness program involves development of an overall plan with appendices that define local response plans and environment sensitivity areas. Geographical Response Plans for water response have been developed for specific important environmentally sensitive areas such as the Northwest, Mississippi River, and rail-specific locations like the Columbia River, Colorado River and Glacier National Park (Flathead River), for example.

The accident prevention program utilizes onboard sensors/wayside detectors to determine brake or wheel problems, and engineering systems to improve track systems. The emergency response program involves an incident response command that includes all-hazards responders, operations personnel and contractors in one unified team. The team has available GIS with identified sensitive features, preplaced equipment and responder locations to streamline response actions. Preplaced equipment for hazardous spills in the Northwest is located in Pasco, Seattle and Spokane Washington. (http://www.unh.edu/workshops/oil_sands_Washington/Oil_Sands_Products_Workshop_Report)

Washington's oil refineries -- two near Anacortes, two in Ferndale and one in Tacoma -- have a combined processing capacity of about 654,000 barrels, of which about 43 percent is turned into gasoline.

The *Cherry Point Refinery*, seven miles south of Blaine, Wash., is the largest oil refinery in Washington with a processing capacity of 234,000 barrels per day. Historically, Cherry Point's crude oil has come from the Alaska North Slope (ANS). Though with decreasing North Slope production, ANS crude now comprises only approximately 50 percent of the Cherry Point Refinery's crude supply. Whether ANS crude or other foreign crudes, approximately 90 percent of the Cherry Point Refinery's crude supply is brought in by petroleum tankers via the Strait of Juan de Fuca and Rosario Strait and delivered directly to the refinery on the Strait of Georgia. The remainder of the crude comes from a pipeline connected to oil reserves in Western Canada. BP has applied for permits for a \$60 million rail yard at its Cherry Point refinery north of Bellingham. The refinery is currently constructing a rail facility to import Bakken crude from North Dakota. The BP refinery would receive about 20,000 barrels a day by rail, less than a tenth of its 234,000 barrel-per-day capacity. This crude oil would replace

some supply currently brought in by ship and serve to maintain production, not increase capacity.

The *Tesoro Anacortes Refinery*, 70 miles north of Seattle, is capable of processing 125,000 barrels per day. It receives feedstock via pipeline from Canada and ANS (Alaska North Slope oil) by tanker from Alaska. It also relies on a variety of crudes from foreign sources. Trains are also delivering Bakken crude oil from North Dakota and Montana to the Tesoro refinery, which recently completed a \$55 million unit train unloading facility rail yard. The goal is to run six trains a week, shipping a total of 50,000 barrels of crude oil from the Bakken formation to the Anacortes refinery on each unit train. Tesoro expanded their receiving capacity to handle the new trains, and can unload two of these trains per day. Each train is about 100 cars long.

The *Shell Anacortes Refinery* has a capacity of 146,000 barrels per day. When the refinery first began operating, most of its crude oil came from Canada via pipeline. Although it continues to receive crude oil from Central and Western Canada, now most of the facility's feedstock arrives by tanker from oilfields on Alaska's North Slope. The Anacortes spur is an 18-20 mile long rail spur that comes off the main line at Burlington, Wash., and goes to the Shell and Tesoro refineries in Anacortes. Shell is exploring the potential to bring Bakken crude oil from North Dakota by rail to March Point for processing. This crude oil would replace some supply currently brought in by ship and serve to maintain production, not increase capacity. The project envisions one train per day in and out of the facility. Plans entail building a rail spur on Shell property with equipment to pump oil from rail cars into the facility at an estimated 50,000 barrels per day of crude oil. (Sightline Institute, *The Northwest's Pipeline on Rails*)

The *Phillips 66 Ferndale Refinery*, 20 miles south of the U.S.-Canada border, has a capacity of 107,000 barrels per day. The refinery processes primarily Alaska North Slope crude oil. It also receives Canadian crude oil via pipeline. Phillips 66 announced in June that it was buying as many as 2,000 railcars to transport shale oil [crude oil from the Bakken formation] to its refineries. It is set to build (completion Dec. 2014) a rail car receiving facility that will allow the plant to take 30,000 barrels per day.

The *U.S. Oil & Refining Co.* in Tacoma has a capacity of 42,000 barrels per day. The refinery is capable of handling weekly 100-car oil unit trains carrying Bakken crude oil from North Dakota at its new \$8 million rail yard. Estimates are that the facility currently accepts 6,900 barrels of crude oil a day. (Sightline Institute, *The Northwest's Pipeline on Rails*)

Terminals, transloading facilities – Existing and proposed

Targa Resources Partners LP in Tacoma has agreed to provide rail unloading and barge loading services. The five-year agreement, which

began in late 2012, allows advantaged U.S. or Canadian crude oil [Bakken or Oil Sands] to be unloaded from railcars at Targa's Tacoma terminal and transloaded onto barges for delivery to the Phillips 66 Ferndale Refinery. The facility also allows for delivery into the San Francisco, Calif., refinery, where crude imported from outside of North America could be replaced. The terminal is capable of receiving individual cars, but as volumes ramp up, it will transition to unit train capability. At full volume, the delivery capability is estimated to be approximately 30,000 BPD. (Sightline Institute, The Northwest's Pipeline on Rails)

Global Partners LP on the Columbia River in Clatskanie, Oregon, Port of St. Helens, announced that it has signed an agreement to acquire 100 percent of the membership interests in a West Coast crude oil and ethanol facility near Portland, Oregon, from Cascade Kelly Holdings LLC. The transaction includes a rail transloading facility serviced by the BNSF (Burlington Northern Santa Fe) Railway, 200,000 barrels of storage capacity, a deep water marine terminal, a 1,200-foot dock and the largest ethanol plant on the West Coast. The plant site is located on land leased under a long-term agreement from the Port of St. Helens. In November 2012, the facility began transloading unit trains of crude oil estimated to be 7,000 barrels per day. (Oregon Dept. of Environmental Quality)

The US Development Group, Hoquiam, Wash., is planning to spend \$80 million constructing a facility at the Port of Grays Harbor's Terminal 3. Plans call for receiving 50,000 barrels of crude oil per day by rail, storing it on site in tanks, and transferring it to barge or vessel. (Sightline Institute, The Northwest's Pipeline on Rails). This proposal is still in discussion phase. Permitting has not begun yet on this potential project.

Westway's Grays Harbor Terminal, Hoquiam, Wash., is located at the Port of Grays Harbor where it currently operates a methanol handling facility. Westway is planning to spend \$50 million building four additional storage tanks, each big enough to store 200,000 barrels of oil. The company hopes that the site will be operational by January 2014, but legal appeals of the permits will likely delay operations. (Sightline Institute, The Northwest's Pipeline on Rails)

Imperium Terminals (Hoquiam, WA) Imperium, a renewable fuels producer, is exploring a crude oil handling facility at the Port of Grays Harbor at the firm's existing site at Terminal 1. The company is proposing to spend \$45 million constructing nine 80,000-gallon storage tanks and other facilities by 2014. Based on rail and vessel traffic estimates reported in news accounts, Sightline estimates that the site is likely to have a capacity of at least 75,000 barrels per day if it is completed. (Sightline Institute, The Northwest's Pipeline on Rails)

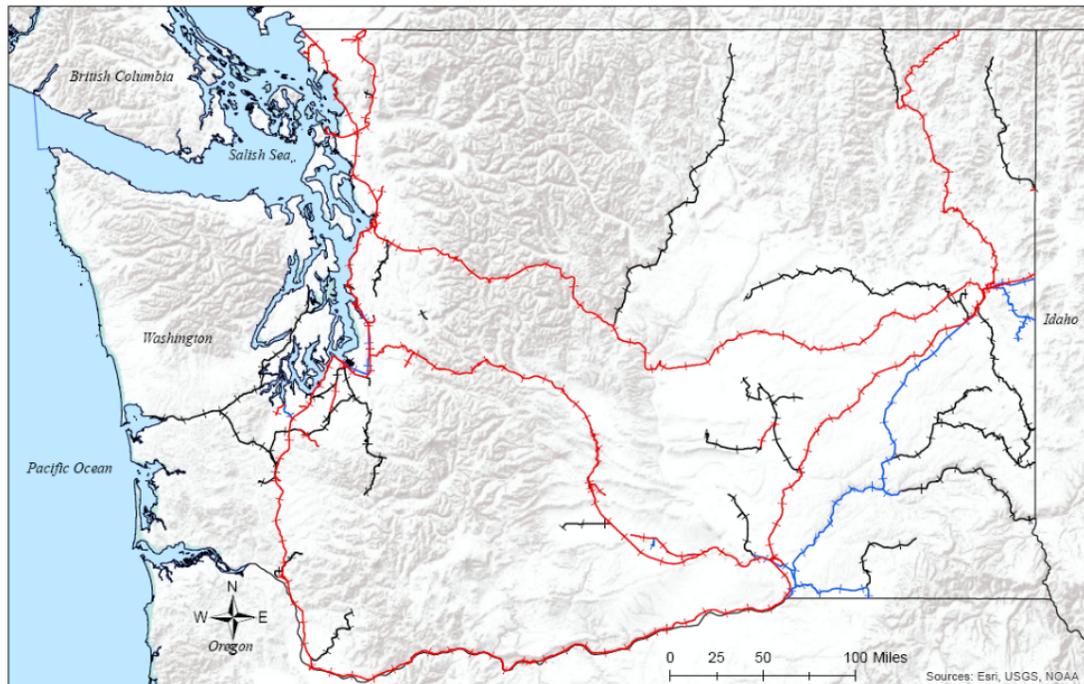
Tesoro / Savage, Vancouver, Wash., Tesoro's plan is to partner with Savage Companies to develop a \$75 to \$100 million rail complex at the Port of Vancouver. The facility is estimated to handle as much as 360,000 barrels per day. Company officials expect the site to be operational by 2014. (Sightline Institute, The Northwest's Pipeline on Rails)

Once the crude oil reaches these non-refining terminals, it may be loaded onto tank vessels (most likely barges) and transported to local refineries or exported out of the state to refineries). This will increase marine traffic and change the risk. We suggest monitoring the results of the Vessel Traffic Risk Assessment and help implement any mitigating measures that are proposed from that process.

Pipeline extension proposal

Proposed changes to Kinder Morgan crude oil pipeline on the Canadian side will allow the capacity on the U.S. side to increase from 170,000 barrels per day to an estimated 225,000 barrels per day.

Rail Lines by Owner



Legend

Owner ——— Other ——— Burlington Northern Santa Fe ——— Union Pacific

B. Definitions

Oil Sands. Oil Sands, tar sands or, more technically, bituminous sands, are a type of unconventional petroleum deposit. The oil sands are loose sand or partially consolidated sandstone containing naturally occurring mixtures of sand, clay and

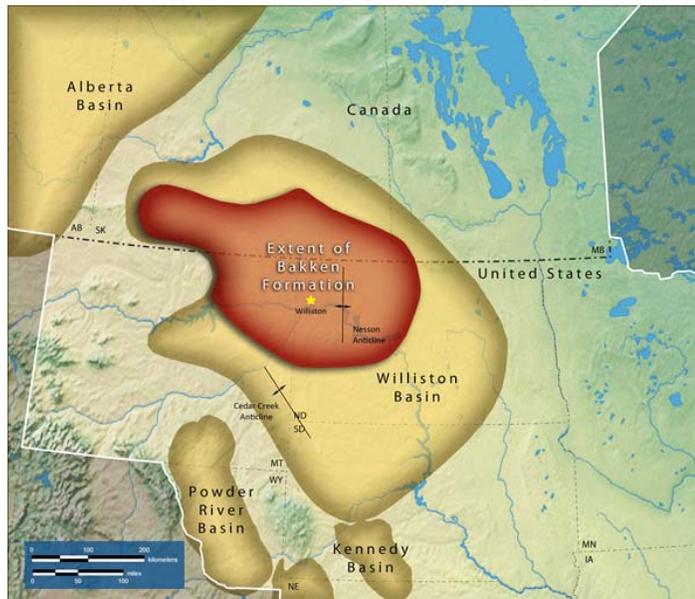
water, saturated with a dense and extremely viscous form of petroleum technically referred to as bitumen (or colloquially “tar” due to its similar appearance, odor and color). Natural deposits are found in extremely large quantities in Canada, some 177 billion barrels or nearly 71 percent of global reserves.

Oil Sands Products. The density and viscosity characteristics of the raw bitumen material require blending for transport through pipeline or by rail tank car. To facilitate moving oil sands from production areas to ports or refineries, the bitumen is blended with diluents to reduce both density and viscosity and improve flow. The most commonly used diluent for mixing with bitumen is natural gas condensate. The blend of bitumen and diluent is often called *dilbit*. When the bitumen is mixed with synthetic crude oil (a partially refined bitumen product), the product is called *synbit*. Bitumen diluted with both a diluent and with synthetic crude oil is *dilsynbit*. As a group, the range of different blends based on bitumen as a base material is referred to *oil sands products*.

Diluents - In order to move bitumen efficiently through transmission pipelines, other petroleum products must be added to dilute it (diluent). These diluted bitumen products are called Oil Sands Products (OSP).

Bakken Crude Oil. Bakken crude oils originate from the Bakken Formation, occupying some 200,000 square miles of the subsurface of the Williston Basin underlying parts of Montana, North Dakota and Saskatchewan, could potentially contain recoverable reserves of up to 24 billion barrels of crude oil.

Map of Bakken Formation and Williston Basin



Source: Energy and Environment Research Center

The rock formation consists of three components: lower shale, middle dolomite, and upper shale. The shale was deposited in relatively deep anoxic marine conditions, and the dolomite was deposited as a coastal carbonate bank during a time of shallower, well-oxygenated water. The middle dolomite is the principal oil reservoir, roughly two miles (3.2 km) below the surface. Both the upper and lower shale components are organic-rich marine shale. (Wikipedia article on Bakken Formation)

The Bakken Formation crude oils are also extracted from the shale deposits are characterized by very low permeability, averaging less than 5 percent porosity. In these deposits, the flow of oil from the rock to an extraction well is limited by the low permeability, fine-grained nature of the rock, which is the basis for the common term “tight oil.” Recovery of oil trapped in these low-permeability rocks requires well stimulation techniques (physical or chemical actions performed on a well to improve the flow of oil or gas from the formation rock to the well bore).

The expanded use of new drilling, fracturing, and recovery techniques have resulted in dramatic increases in oil production. North Dakota's oil production recently reached 730,000 barrels per day. Bakken production has expanded so rapidly that companies have difficulties transporting oil to other parts of the country. Rail transport is allowing Bakken crude to be shipped to major terminals on the East and West coasts of the country where pipelines do not exist, or where pipeline capacity is limited.

C. Characteristics

1. Oil Sands Products

Oil Sands Origin. Alberta oil sands are believed to originate from a standard crude oil deposit that has undergone a significant degree of biodegradation. The lighter, shorter chain alkanes in the petroleum mixture have been degraded by naturally occurring microorganisms, leading to a partially weathered product with a predominance of large molecules. The biodegradation occurred at low temperatures (i.e., < 80° C), meaning pasteurization (sterilization) did not occur and microbial populations could continue to metabolize petroleum hydrocarbons.

The degree of biodegradation that may occur after a spill of oil sands products will be dependent on the extent to which the bitumen deposit was degraded prior to extraction and the inherent biodegradability of the diluent. Therefore, source bitumen that originally underwent a high degree of biodegradation would likely experience little further degradation after a release and weathering of the lighter diluent components. However, there are few experimental data available to fully evaluate the biodegradation potential oil sands products spilled into fresh or salt-water environments.

Bitumen Chemical Properties. *In situ* biodegradation of crude oil leads to a bitumen containing a lower proportion of paraffins (saturated hydrocarbons without rings) and naphthenes (saturated hydrocarbons with rings); and a higher proportion (>50 percent)

of aromatics (hydrocarbons with one or more aromatic nuclei), which results in the increased viscosity and density characteristics of bitumen. Aromatics made up 37 percent of the total weight of Athabasca bitumen, followed by resins (25.7 percent), and by saturates and asphaltenes (both 17.3 percent). Gas chromatography has shown that Alberta bitumen is characterized by large, unresolved compounds (n-C₁₀ to n-C₄₀) and a near absence of n-alkanes; C₃₉ and larger molecules made up 56.96 percent of the weight of Athabasca bitumen.

Bitumen Physical Properties. Locating information on the physical properties of Alberta oil sands products can be challenging, as some of the specific physical and chemical properties data are considered to be proprietary business information. For this reason, it has been difficult for regulators and others in the scientific community to realistically model physical behavior in the environment.

Bitumen is generally characterized as denser than standard crude oil. The density of oil sands bitumen depends on the specific reservoir and temperature of the source material. Athabasca bitumen tends to be denser than freshwater, but less dense than saltwater, under standard conditions of 15.56° C. Between 25 and 40° C, Athabasca bitumen is less dense than water; Cold Lake Bitumen is denser than freshwater below ~40° C but less dense than saltwater.

As temperature increases, viscosity and density decrease; in some cases, this permits the raw bitumen to be transported in its native, albeit heated, state.

Bitumen can be orders of magnitude more viscous than conventional oils. At 25° C, the viscosity of conventional crude is ~13.7 cP (centipoise), while for bitumen it is >1,000,000 cP. Athabasca bitumen must approach 200° C, before its viscosity becomes similar to standard crude oil viscosity at ambient temperatures. Similarly, Cold Lake Bitumen must exceed 120° C before its viscosity is similar to standard crude viscosity at ambient temperature.

API (density) values for crude oils range from approximately <22-42, with refined products and condensates ranging higher. A summary of crude oil and other petroleum product densities is as follows:

- Gas Condensates – ≈ 42 to 55°API
- Light Crude Oils – ≈ 31 to 42°API - varies
- Medium Crude Oils – ≈ 22 to 31°API
- Heavy Crude Oils – ≈ <22°API
- Alberta Bitumen – ≈ 8°API prior to being mixed with diluent
- Water (≈10°API); Gasoline (≈63°API); Fuel Oil #2 (≈30-38°API)

Diluents

Diluents and Synthetic Crude. According to specifications established by Enbridge, the diluents used in the transport of oil sands products are light hydrocarbons with a typical density between 0.6-0.775 g/ml, a maximum sulfur weight by percent of 0.5 percent, and maximum viscosity of 2.0 cST (centistokes). Natural gas condensate, a liquid that under standard ambient conditions contains pentanes and heavier hydrocarbons produced from processing natural gas, is currently the most commonly used diluent. New pipelines have been proposed to supply diluent to Alberta and meet the growing demand for, but decreasing supply of, diluents in Canada.

Another method for upgrading bitumen for transport is to blend it with synthetic crude oil to make a product called “synbit.” Synbit is a mixture of bitumen with synthetic crude—bitumen that has undergone upgrading through coking and hydrolysis to remove the larger molecules and decrease viscosity. Currently, this method is less expensive than mixing the bitumen with diluent. Projections suggest that the use of synthetic crude as a diluting agent will increase over the next decade, while the use of natural gas condensate will remain steady.

The characteristics of diluents vary across the range of products. Crude Quality Inc. provides an in-depth online list of the physical and chemical properties of several diluents.

Dilbit and Synbit Composition for Transport. The composition of dilbit varies between 25-30 percent diluent and 70-75 percent bitumen, depending on the viscosity of the bitumen and the density of the diluent. The ratio can be as high as 40 percent diluent for heavier bitumen. The diluent required for mixture can be decreased if the asphaltene fraction is removed from the parent bitumen. Because the diluent and bitumen are both hydrocarbon-based, the two are completely miscible.

For synbit, the mixture is typically 50 percent synthetic crude and 50 percent bitumen. Operating and spill-response experience reported by the Trans Mountain Pipeline is that dilbit and synbit behave as homogeneous products with fluid properties similar to other heavy crude oils.

Products transported in the Trans Mountain system, including dilbit and synbit crude oil, must meet the following *maximum* quality limits of the Canadian National Energy Board-approved Pipeline Tariff

- Reid vapor pressure: 103 kPa (kilopascal)
- Sand, dust, gums, sediment, water or other impurities (total in aggregate): 0.5 percent
- Receipt Point temperature: 38°C
- Density: 940 kg/m³ (kilograms per cubic meter)
- Kinematic Viscosity: 350cSt (centistokes)
- Having any organic chlorides or other compounds with physical or

chemical characteristics that may render such Petroleum not readily transportable by the Carrier.

Corrosiveness of Oil Sands Products

Overview of Existing Research on Pipeline Corrosion. A recurring source of contention in discussions about the risks of transporting oil sands products via pipelines has centered on corrosion and the inherent corrosiveness of those products relative to traditional crude oil. Several research reports exist on the subject of oil sands products corrosiveness and although not entirely conclusive, the data suggest that oil sands products are generally *not* significantly more corrosive than other heavy crude oils being transported through pipelines. A brief overview of the findings includes the following points:

- Sulfur content of Alberta oil sands products ranges between 2-5 (weight percent). There are conflicting reports regarding how these sulfur levels compare to other heavy crude oils. That is, one report determined oil sands products to be generally comparable to other heavy crudes, with the exception of a few specific products; however, a U.S. Geological Survey study reported higher sulfur content as a fundamental difference between natural bitumen and conventional crude oils as a result of *in situ* biodegradation.
- TAN (total acid number) values of Alberta oil sands products ranged from .5-2.5 (mgKOH/g), which is comparable to many conventional heavy types of crude. Products with TAN values higher than 0.5 are generally considered “potentially corrosive,” but in lab testing, the oil sands products were not found to be significantly different from comparable heavy crudes and not corrosive enough to be a concern to pipeline operators.
- Water content (expressed as BS&W, basic sediment and water) in oil sands products is comparable to other crudes, with the required maximum allowable threshold set by pipeline operators.
- Sediment content in dilbit crudes was found to be lower than or comparable to that of conventional crudes, with the exception of one dilsynbit blend that was found to have more than double the solids content of most other crudes. The data, however, only indicate the total amount of sediments, and do not provide information on the size distribution. It is unknown how the solids in the conventional crudes compared to those in dilbits.
- Sediment build-up in low or high spots in the pipeline interior can lead to corrosion.

In summary, research to date does not indicate that oil sands products are significantly more corrosive than other heavy crude oils. A National Academy of Sciences study currently underway and scheduled to be completed by the end of 2013 will analyze whether transportation of dilbit by transmission pipeline is subject to an increased likelihood of release compared with pipeline transportation of other crude oils. This study will be a review of existing literature and will not include any original research. PHMSA (Pipeline and Hazardous Materials Safety

Administration) data presented to the National Academy show that since 2002 there have been no releases of oil caused by internal corrosion from pipelines carrying dilbit. However, this does not imply that corrosion is not a concern: Combined internal and external corrosion account for 37 percent of non-small pipeline accidents for crude oil.

2. Bakken Crude Oil.

Bakken crude is considered a light (API Gravity from 36 to 44 degrees) –sweet (containing less than 0.42 percent sulfur) low viscosity crude oil with significant quantities of light, volatile hydrocarbons. Bakken crude is highly flammable and easily ignited at normal temperatures by heat, static discharges, sparks or flames (flash point less than -35°C and auto-ignition temperature of approximately 250 °C). Vapors may form explosive mixtures with air, and vapors may travel to source of ignition and flash back. Vapors may spread along ground and collect in confined areas such as sewers and tanks. The Upper Explosive Limit is estimated at 8 percent v/v): 8 (estimated). Lower Explosive Limit (4 percent v/v): 0.8 (estimated). If burned, carbon monoxide, sulfur oxides, nitrogen oxides and smoke particulates may be created.

The main properties and constituents of Bakken crude oil are shown and compared to synthetic crudes and diluted bitumen oils in the table below.

Summary of General Characteristics of Crude Oil That Would Be Transported by the Keystone XL Project (From: Keystone XL Project – Draft Supplemental Environmental Impact Statement – EPA, March 2013)

Characteristic	Synthetic Crude Oil ^a	Diluted Bitumen ^b	Bakken Shale Oil ^c
Density	na	na	827 kg/m ³
Specific gravity	0.84–0.86 ^e	0.9–1.2	0.82–0.83
Viscosity	na	52 to 96 centistokes at 38°C	na
Flammability	na	Class B, Division 2: Flammable Liquids	Class B, Division 2: Flammable Liquids
Composition	Gas oils (petroleum), hydrodesulfurized 60% Naphtha (petroleum), hydrotreated heavy 10-30% Naphtha (petroleum), hydrotreated light, 3-7% Butane 1-5% Hydrogen sulfide (H ₂ S) 0.001-0.01% BTEX 1-1.5%	Bitumen 40-70% Light naphtha 15-40% Natural gas condensate 15-40% BTEX 1-1.5%	Light hydrocarbons <30% Pentanes 3-4% Hexanes 4-6% Heptanes 6-8% Octanes 6-8% Nonanes 4-6% Decanes 1-3% BTEX 1-3%
Flash point	68°F (20°C)	-0.4°F (-18°C)	na
Toxicity ^d	na	Class D, Division 2, Subdivision A: Very Toxic Material	na
Solubility in water ^e	Insoluble in cold water ^f	Insoluble ^f	Insoluble
Pour point	-5.8°F (-21°C)	-22°F (-30°C)	-25°F (-32°C)
Sulfur	0.25%	3.6%	0.17-0.20%
Other properties	Oxides of carbon, and nitrogen, aldehydes form upon combustion. Hazardous sulfur dioxide and related oxides of sulfur may be generated upon combustion.		

^a Husky Energy 2011.

^b Imperial Oil 2002.

^c Crudemonitor 2012a. Five-year average was used for numbers.

^d Table 3.13.5-12, Final Environmental Impact Statement (Final EIS).

^e Table 3.13.5-12, Final EIS.

^f Insoluble, but volatile organic compound and semivolatile organic compound constituents are soluble, (e.g., benzene, toluene, polycyclic aromatic hydrocarbons).

^g Specific gravity for water = 1.0.

Notes: na = not available; kg/m³ = kilograms per cubic meter; BTEX = benzene, toluene, ethylbenzene, and xylenes.

D. Response strategies

Oil Sands Products.

Although the physical characteristics of an oil sands product as blended for transport are expected to resemble those for typical crude oil products, uncertainties exist about the behavior of spilled and weathered product in the environment. Limited spill response experience reported by the Trans Mountain Pipeline and Western Marine Spill Response Corporation (WCMRC) during the 2007 Burnaby Harbor Spill is that the synbit spilled into the marine environment of Burrard Inlet behaved as a homogeneous product with fluid properties similar to other heavy crude oils. However, oil sands products may differ from crude oils in the rate at which lighter ends of the mixture volatilize, particularly in warm weather. As a result—and as demonstrated during the Enbridge Kalamazoo River Spill—spills of oil sands products may be potentially submerged or sinking, especially under high-flow and high-sedimentation conditions. As a result, responders should anticipate

the potential for floating oil, and as time progresses, subsurface (neutrally buoyant and sinking) oil.

Procedures for responding to spills of Group IV and V oils have been described elsewhere and will not be repeated here. A few details of response actions and lessons learned from the limited case study histories for oil sands products (and one rail incident involving a heavy oil product) are reviewed below to provide insight into potential issues and challenges associated with these oils.

Case Studies. Two water-borne spills of oil sands products have recently occurred: the Kalamazoo River Spill in Marshall, Michigan, (dilbit) and the Burnaby Harbor Spill in Burnaby, British Columbia, (synthetic crude). Like all spills, these reflect unique circumstances and settings, limiting the ability to extrapolate universal lessons learned about oil sands products behavior and response methods. Due to the small number of case studies, this section will also examine the Wabamun Lake Spill, a railcar derailment that spilled Bunker C oil into a freshwater system in Alberta, Canada.

Kalamazoo River Spill

Spill Summary

Two types of dilbit oil were spilled during the Enbridge Pipeline spill into the Kalamazoo River system: Cold Lake and McKay River. Enbridge initially reported the size of the release to be 819,000 gal. This was later revised upward to 843,000 gal. Other estimates by the EPA have been substantially higher, up to 1.1 million gal. The reasons for the discrepancies in spilled-volume estimates are not clear and have not been resolved, but will factor into determination of Clean Water Act penalties.

The dilbit initially floated on the fresh water of Talmadge Creek and the Kalamazoo River. However, after mixing with sediments and the evaporation of the light hydrocarbons, some oil became dense enough to sink. As a result, there were periods during the response when the dilbit was simultaneously floating, submerged in the water column, and on the bottom of the river. Beyond the characteristics of the oil, water temperature, the presence of sediments, and the speed of the river affected oil.

Technologies Used in Recovery

An important factor impeding oil removal efforts during the Kalamazoo River Spill was the fast moving water of the river and Talmadge Creek. Recovering oil in fast-moving water is difficult, as oil tends to flow under containment booms and skimmer efficiency is greatly reduced, necessitating more rapid responses further downstream. In these situations, the Coast Guard recommends installing underflow dams, overflow dams, sorbent barriers, or a combination of these techniques.

Enbridge responders, with personnel from Terra Contracting and the Baker Corporation, used:

- *Oil booming and sorbent booming* at 33 oil-spill-containment and control points. At the most heavily boomed location, 176,124 feet of boom was deployed.
- One *Gravel-and-earth underflow dam* at the meeting of the contaminated marsh and Talmadge Creek. This site was chosen because it was accessible to heavy equipment. Responders did not have the traditional materials for adjustable underflow dams on-site and had to construct one out of surplus materials and, therefore, were late deploying the technology.
- Three *vacuum trucks* were used to recover oil at the underflow dam. Nine other vacuum trucks were deployed at other sites.
- *Oil skimmers* were also used to recover oil.
- On 25 acres, *dredging* was used to recover oil. This method was the most successful in terms of the amount of oil recovered.
- Responders considered plugging the steel culvert pipe under Division Drive with earth to contain the oil upstream, but the quick water flow prohibited attempting this method.

At the peak of deployment, 2,011 personnel engaged in oil spill recovery. As of summer 2013, the cleanup efforts were continuing. In October 2012, EPA directed Enbridge to dredge approximately 100 acres of the Kalamazoo River, as oil continued to accumulate in three areas. The main concern with the presence of this oil was that during a flood, the pools of oil could remobilize and contaminate parts of the river that had already been cleaned. EPA chose to move forward with dredging because it was deemed the most effective method during the original recovery efforts. Enbridge contested the EPA assessment, stating that further dredging would do more harm than good to the Kalamazoo River ecosystem. In March 2013, EPA ordered another round of dredging to remove submerged oil and oil-contaminated sediments upstream of the Ceresco Dam, in the Mill Ponds area, around Morrow Lake, and installation of sediment traps at two locations. The required dredging was to be completed by the end of 2013.

Lessons Learned Regarding Recovery Efforts

Three main issues were identified related to Enbridge's recovery efforts:

1. *Communication* –The spill occurred during the night and initial responders were not aware of the severity of the spill or the type of oil spilled, which led to impaired decision-making. Responders had no estimate of a volume release when the first round of containment methods was deployed.
2. *Lack of resources* – Originally, Enbridge responders did not have the resources to contain or control the flow of oil into the surrounding bodies of water (such as materials for underflow dams). Enbridge initially brought in contractors from Minnesota, a 10-hour drive from the spill site, which slowed recovery time. The EPA on-scene coordinator provided Enbridge with the contact information for local contractors to keep recovery efforts moving forward.
3. *Lack of Training* – During the initial response, Enbridge personnel placed the containment booms too far downstream to be effective, and also used booms that were incompatible with fast-moving water. This was related to both lack of

training, and also the lack of communication and knowledge regarding the severity of the spill.

Burnaby Harbor Spill

Spill Summary

On July 24, 2007, approximately 1,400 barrels (58,800 gal.) of synthetic crude leaked from the Westridge Transfer Line in Burnaby, British Columbia. After the oil was spilled, it flowed in Burnaby's storm sewer systems until it reached Burrard Inlet. In total, eleven houses were sprayed from the rupture, fifty properties were affected, 250 residents voluntarily left, and the Burrard Inlet's marine environment and 1,200 meters of shoreline were affected by the spill.

Five minutes after the rupture, the pipeline operator shut down the Westridge Pipeline, and the Westridge dock delivery valves were closed. However, the Burnaby Terminal is sited at a higher elevation than the rupture site, so gravity intensified the release of the oil. Twenty-four minutes after the rupture, the Burnaby Terminal and the Westridge Pipeline were fully isolated. Kinder Morgan established a unified command with the British Columbia Ministry of Environment and the National Energy Board (NEB) to coordinate the response. Nevertheless, the initial failure to fully shutdown the Westridge Pipeline was contrary to Kinder Morgan's standard shutdown procedures. Cleanup took months and cost roughly \$15 million and resulted in the recovery of approximately 1,321 barrels of oil.

In 2011, three companies – two contracting companies and Trans Mountain Pipeline L.P. – pleaded guilty to violating the Environmental Management Act for introducing pollutants into the environment, and will each pay a \$1,000 fine and donate \$149,000 to the Habitat Conservation Trust Foundation. Trans Mountain Pipeline L.P. will be required to pay an additional \$100,000 to fund training and education programs.

Technologies Used in Recovery

Kinder Morgan primarily relied on contractors to recover the oil (per Ministry of the Environment, 2007). The contractors used three distinct methods to recover the oil, based on the oil's location:

1. *Residential areas.* Peat moss was used successfully to absorb oil on land.
2. *Storm sewers.* Oil in the storm sewers was vacuumed up. Much of the oil was collected in the pump station.
3. *Burrard Inlet.* The responders were able to set up floating booms outside the storm sewer tunnels to collect oil that reached the Inlet. To treat the oil that had adhered to the shoreline, responders successfully used the chemical shoreline cleaner Corexit 9580.

Lessons Learned

The recovery effort during the Burnaby Harbor Spill was relatively successful. Because the synthetic crude traveled on a predictable path through the storm sewer system, responders were able to set up booms in a quick and efficient manner. We

were not able to find any reports of the oil sinking or being submerged in the water column. However, extrapolating the oil behavior in this case to other potential synthetic crude spills is difficult because most of the oil was collected in the storm sewer systems and on land.

The primary issue in this case study was the lack of communication between city contractors and Kinder Morgan during the excavation process. As with the Kalamazoo Spill, failure to follow administrative procedures significantly increased the amount of oil spilled.

Wabamun Lake Spill

Spill Summary

Forty-three Canadian National Railway (CN) freight railcars derailed on August 3, 2005, adjacent to Lake Wabamun, just west of Edmonton, Alberta. The derailment resulted in 4,400 barrels of Bunker C oil and 554 barrels of pole-treating oil being spilled, with approximately 1,235 barrels¹ of the oil entering the temperate Lake Wabamun. The spill was caused by a faulty train track that had at least 13 undetected defects. Though Bunker C is not an oil sands product, it is a heavy oil and can have a density approaching that of water, and thus could be similar to undiluted bitumen. In this case, veteran spill responder Ron Goodman reported that the oil began to sink with limited amounts of weathering and sedimentation.

CN used an oil response contractor to recover the spilled oil. However, after the contractor's initial efforts, it became clear that the company was not sufficiently experienced in oil spills of this magnitude or of this type of oil. As a result, it was not able to contain the spill and CN eventually had to contract the cleanup to a more experienced response organization. The new response contractor surveyed oiling conditions using the Shoreline Cleanup and Assessment Technique (SCAT) and then moved to cleaning up individual shore segments. A number of reed beds were cut because the reeds became a continuing source of surface contamination. In total, approximately 1,076 barrels of oil was recovered and the response effort was completed in October 2005.

During the cleanup, there was strong public perception that the government failed to do its job, specifically, that the recovery efforts were more concerned with getting the track cleared and working again than with any ecological effects. This was compounded by the delay in beginning cleanup efforts due to lack of available equipment. As a result, the Alberta Ministry of the Environment established the Environmental Protection Commission in August 2005 after the spill; First Nations sued CN and were awarded \$10 million. CN spent approximately \$132 million in cleanup costs and paid \$1.4 million in fines, and additionally made changes to its spill procedures and equipment requirements.

¹ The amount of oil that entered Lake Wabamun is debated and varies greatly depending on the source. This estimate is an average of the most commonly cited amounts.

Technologies Used in Recovery

Two main elements were taken into consideration during the Lake Wabamun Spill response: weather and the type of oil spilled. Both of these elements affected the behavior of the spilled oil, such as when the oil submerged and entered the water column or when the oil sank to the bottom (per Fingas, 2010). Responders used the following technologies:

- *Sorbent and containment booms* were the first technologies deployed at the site. Sorbent booms were ineffective in containing the Bunker C oil and there were not enough containment booms to stop the spread of oil due to high winds. It was necessary for additional equipment to be brought in from across Canada and the United States.
- *Dikes* were successfully built to stop the flow of oil into the lake. Once the ditches and dikes were completed, no further oil reached the lake.
- *Vacuum trucks* helped recover the oil.
- *Hand shoveling and skimmers* were relatively successful.
- *Sorbent pads* were used to probe the bottom of Lake Wabamun in order to detect oil that had settled on the bottom. The Bunker C oil had formed a skin and did not adhere to the pads, making this technology ineffective.
- *Video cameras for detection* were only successful in some shallow water situations due to the dispersed nature of the oil.
- *Nets of ten millimeters* were ineffective. Responders had to move toward very fine netting, which inhibited water flow. Ten-millimeter nets were tried due to the previous success with this size of net in collecting bitumen.
- Responders had very limited success in recovering oil once it reached the bottom.

It is important to note that it was not until four days after the derailment that responders realized that pole treating oil had been spilled, in addition to the Bunker C oil. The pole treating oil was mixed with other chemicals to be used as a wood preservative and potentially contained toluene, benzene and its derivatives, naphthalene and its derivatives, phenyls, and polycyclic aromatic compounds. As a result, possible workplace hazard associated with the chemical was neither recognized nor communicated until days later.

Lessons Learned

The spill response effort at Wabamun Lake was not efficient particularly due to management decisions. An emergency operations center under the unified command system (UC) was not set up. Under UC, response agencies collaborate on the response effort, with the main purpose to provide guidelines for multiple agencies to work together efficiently. This was the Transportation Safety Board of Canada's primary criticism of the CN response efforts. Other shortcomings observed during the response effort included:

- *Limited amounts of response equipment in close proximity to the spill.* This was problematic as it led to both negative public relations as citizens witnessed the

oil spreading without an adequate response, as well as responders missing crucial time in containing the spill. Later, it was determined that some response equipment in the region was not made available because it was held in reserve in case of a concurrent environmental disaster.

- *The need for contingency planning.* CN implemented its Dangerous Goods Emergency Response Plan but failed to install a unified command. The lack of a central structure led to considerable confusion in the early stages of recovery as more responders arrived on scene and there was no organizational structure. Also, the contingency plan CN had in place was generic and had no specific guidelines for the Wabamun Lake area. The plans had not been tested recently and there had been little contact with response groups in the area.
- *Lack of information regarding the behavior of heavy oil when spilled.* In this case, the lack of information regarding the interaction of oil and fine sediments and how the changes in surface water temperature would influence submerged oil, tar ball formation, and the long-term fate of submerged oil in marine and fresh water ecosystems affected cleanup efforts.
- *Limited number of tested and effective oil detection technologies.* Response crews lacked appropriate technology for detecting oil once it reached the bottom of the lake.

Bakken Crude Oil Response Strategies.

Response to spills of Bakken Crude Oils are likely similar to response to other light, volatile rich crude oils. The effectiveness of standard spill response techniques applied to spills of Bakken Crude Oils needs to be synthesized for this report. Specific responder and public health factors to be taken into account during response are discussed in the following section.

E. Bakken Crude Oil Safety issues

(Cenovus Energy – MSDS and 2012 Emergency Response Guidebook)

Because of the presence of up to 30 percent (by volume) light volatiles in Bakken Crude, the potential for fire and explosion is the single largest risk to responder and public health. Accordingly, extreme caution should be exercised during the initial stages of response. The following general response guidelines are from the 2012 Emergency Response Guidebook prepared by the U.S. Department of Transportation – Pipeline and Hazardous Materials Safety Administration and Transport Canada.

As an immediate precautionary measure, isolate spill or leak area for at least 50 meters (150 feet) in all directions. For large spills, consider initial downwind evacuation for at least 300 meters (1000 feet). If tank, rail car or tank truck is involved in a fire, ISOLATE for 800 meters (1/2 mile) in all directions; also, consider initial evacuation for 800 meters (1/2 mile) in all directions. For incidents with the potential to involve multiple rail cars or large tanks, this evacuation distance should be expanded accordingly. Keep unauthorized personnel away from the response. Stay upwind, keep out of low areas and ventilate closed spaces before entering unless atmospheric concentrations of contaminants have been evaluated.

Fire Precautions: All these products have a very low flash point: Use of water spray when fighting fire may be inefficient.

Small Fire

- Dry chemical, CO₂, water spray or regular foam.

Large Fire

- Water spray, fog or regular foam.
- Do not use straight streams.
- Move containers from fire area if possible without risk.

Fire involving Tanks or Car/Trailer Loads

- Fight fire from maximum distance or use unmanned hose holders or monitor nozzles.
- Cool containers with flooding quantities of water until well after fire is out.
- Withdraw immediately in case of rising sound from venting safety devices or discoloration of tank.
- ALWAYS stay away from tanks engulfed in fire.
- For massive fire, use unmanned hose holders or monitor nozzles; if this is impossible, withdraw from area and let fire burn.

Personnel precautions:

Only appropriately trained personnel should respond to uncontrolled releases. Avoid direct contact with material; use appropriate personal protective equipment. Inhalation or contact with material may irritate or burn skin and eyes. Fire may produce irritating, corrosive and/or toxic gases. Vapors may cause dizziness or suffocation. Wear positive pressure self-contained breathing apparatus (SCBA) until atmospheric conditions have been evaluated. Structural firefighters' protective clothing will only provide limited protection.

Caution: Hydrogen sulfide may accumulate in headspaces of tanks and other equipment, even when concentrations in the liquid product are low. Factors increasing this hazard potential include heating, agitation and contact of the liquid with acid or acid salts. Assess the exposure risk by gas monitoring. Overexposure to hydrogen sulfide may cause dizziness, headache, nausea and possibly unconsciousness and death.

Environmental precautions: Prevent material from entering soil, waterways, drains, sewers, or confined areas. Runoff from fire control or dilution water may cause pollution.

Small Spill or Leak

Eliminate all ignition sources (no smoking, flares, sparks or flames in immediate area). All equipment used when handling the product must be grounded. Do not touch or walk through spilled material. Stop leak if possible without risk. Prevent entry into waterways, sewers, basements or confined areas. A vapor suppressing foam may be used to reduce vapors. Absorb or cover product with dry earth, sand or

other non-combustible material and transfer to containers. Use clean non-sparking tools to collect absorbed material.

Large spill

Dike far ahead of liquid spill for later disposal.

Water spray may reduce vapor but may not prevent ignition in closed spaces.

First Aid

Move victim to fresh air.

Call 911 or emergency medical service.

Give artificial respiration if victim is not breathing.

Administer oxygen if breathing is difficult.

Remove and isolate contaminated clothing and shoes.

In case of contact with substance, immediately flush skin or eyes with running water for at least 20 minutes.

Wash skin with soap and water.

In case of burns, immediately cool affected skin for as long as possible with cold water.

Do not remove clothing if adhering to skin.

Keep victim warm and quiet.

Ensure that medical personnel are aware of the material(s) involved and take precautions to protect themselves.

II. CONCLUSIONS

Tar sand oils (and their derivatives) and Bakken Crude represent new and unique challenges to oil spill preparation and response community in the Northwest, owing to their unique characteristics, their relatively recent and dramatic increase in volumes shipped to new areas within the Northwest via new routes and transportation methods. Although standard oil spill response technologies, equipment, and experience in the Northwest is applicable to these new products, the locations and effectiveness of equipment currently staged in the Northwest needs to be further evaluated. Several key differences from the types of oils traditionally shipped in the Northwest (the potential for sinking oils and the potential for explosion of some products, for instance) highlight the need for continued evaluation of all aspects of response applied to these new products.

III. RECOMMENDATIONS

The Emerging Risks Task Force recommends that the Northwest Area Committee and its participants:

- Continue to watch developments in the push to develop new crude oil terminal projects and the corresponding increase in rail and vessel transport. This should include monitoring the Vessel Traffic Risk Assessment as one way to gage the increase in risk for the Northwest.

Continue to gather, analyze, and distribute information relative to response to spills of tar sand oils (and their derivatives) and Bakken Crude in the Northwest. In particular, the effectiveness of standard oil response equipment and strategies in addressing spills of Oil Sands Products and Bakken Crude oils needs to be evaluated, and the effects of spills on potentially impacted environments need to be available prior to the event of spills in order to streamline the response.

- Synthesize and incorporate information on response safety and appropriate measures to increase responder and public health and safety into appropriate chapters of the NW Area Contingency Plan, and make that information available for incorporation into local emergency management plans. Evaluate facility response plans to make sure appropriate safety information is available and consistent with the NW Area Contingency Plan.

The Area Planning Committee will continue to support and monitor the outcome of the current risk studies, in particular the joint Vessel Traffic Risk Assessment, which could lead to a series of recommendations to manage the changing risks in the Northwest.

Monitor studies that are occurring in Canada to support the various proposed projects to improve our understanding of the fate and effects, efficacy of dispersants and long-term toxicity of OSP.

Study the distribution of response equipment between inland and marine areas to assess whether we are prepared for the changing inland risks.

IV. FINDINGS: COAL

A. Transportation picture

The Powder River Basin (PRB) supplies 40 percent of the coal in the United States. It is the primary source for coal shipped or planning to be shipped from West Coast coal ports. The PRB bridges both Wyoming and Montana. Mining companies such as Arch Coal and Peabody Coal operate there. Peabody Energy's PRB operations include coal seams up to 100-feet thick and include train-loading capabilities. Peabody Energy's operations in Wyoming produce more than 140 million tons of coal each year for customers.

There are two existing coal ports on the West Coast of Canada. The first, in Prince Rupert, British Columbia, is the home of Ridley Terminals Inc. The port is serviced by Canadian National (CN) Railway. Western Canadian mines export metallurgical and thermal coal. The facility can load at a rate of 9,000 tonnes per hour. The coal port has an annual shipping capacity of 12 million tonnes and storage capacity of 1.2 million tonnes. The port moors vessels of 325 meters LOA (length overall), 50-meters beam, 22-meters draft and 250,000 DWT (deadweight tonnage).

The second coal port, Roberts Bank Superport, a twin-terminal port facility in the greater Vancouver area, has an annual shipping capacity of 27.3 million tonnes. Its Westshore Terminal opened in 1970. The coal export terminal located at Roberts Bank, Delta, British Columbia, operates only 500 meters from the United States border. It is Canada's No. 1 export coal facility, surpassing the combined total coal exports of all other Canadian facilities. Westshore has also been the busiest single coal export terminal in all of North America, bringing in billions of dollars of export revenue for Canada and British Columbia. In recent years, Westshore has proved to be an increasingly popular choice on the West Coast for United States mines, particularly those in the Powder River Basin in Montana and Wyoming.

Proposed coal terminals on the U.S. West Coast

The Gateway Pacific Terminal (GPT) is located at Cherry Point - Ferndale, Washington. The proposal envisions an annual shipping capacity of 48 million tons.

The Millennium Bulk Terminals - Longview, Washington, has a proposal on the table to ship 44 million tons annually from the site of the former Reynolds Aluminum smelter in Cowlitz County.

The Port of Morrow in Boardman, Oregon, would have a proposed annual 3.5 - 8 million tons annual shipping capacity. The project would ship coal from the U.S. Intermountain region to Asian markets. Coal would be shipped by rail from Wyoming and Montana to the Port of Morrow. It would be transferred and loaded onto barges to be shipped down the Columbia River to Port of St. Helens' Port Westward Industrial Park. There, transloaders would transfer the coal onto covered oceangoing Panamax ships.

Railroad Routes:

Sandpoint, Id. to Spokane, Wash. (BNSF - 78.3 Miles) - The Montana Rail Link route from Mossmain would converge with BNSF direct coal from Shelby at Sandpoint, Id. and move on the BNSF line to Spokane, Wash. All (100 percent) BNSF export coal and oil to the Pacific Northwest moves over this 78.3-mile line segment. This line is commonly known as the "Funnel," and is the second-busiest rail corridor in Washington.

Stevens Pass / Cascade Tunnel - BNSF's Everett-Spokane line, which passes through the Cascade Tunnel at Stevens Pass, is the BNSF's major northern transcontinental route for double-stack intermodal container trains. It is heavily used, operated at about 70 percent of practical capacity in 2008. Empty oil tank cars and coal cars return eastward on this line.

Columbia River Gorge - The BNSF's Vancouver-Pasco line, which follows the Columbia River along the north side of the Columbia River Gorge, is used by double-stack intermodal container trains moving east and grain trains moving west to Pacific Northwest export grain terminals. The line is operating today at about 80 percent of practical capacity. This is the primary route for loaded oil and coal unit trains.

North-South I-5 Corridor - BNSF's line connecting Seattle with Portland, Ore., is the most heavily trafficked rail line in Washington State, conveying BNSF and UP trains (the latter via trackage rights) to and from the major Pacific Northwest ports. The corridor hosts an average of 58 freight trains each day. PRB to Pacific Northwest export coal tons will move over this route from Vancouver, Wash., to Longview and between Longview, and Seattle. Additionally, this is the route for Bakken crude oil transport to the Northwest.

Should these various rail-to-terminal projects be permitted and built, there will be an associated increase in vessel traffic to move the coal out of the state (or out of Canada through U.S. waters). It is not known but we can expect an associated increase in bunkering with the increase in vessel traffic. We suggest that we wait for the results of the VTRA before making conclusions on how this may change the risk picture for the Northwest.

Should these various rail to terminal projects be permitted and built, there will be an associated increase in vessel traffic to move the coal out of the state (or out of Canada through U.S. waters). It is not certain but expectations are for an associated increase in bunkering with the increase in vessel traffic. We suggest waiting for the results of the Vessel Traffic Risk Assessment before forming conclusions as to how this may change the risk picture for the Northwest.

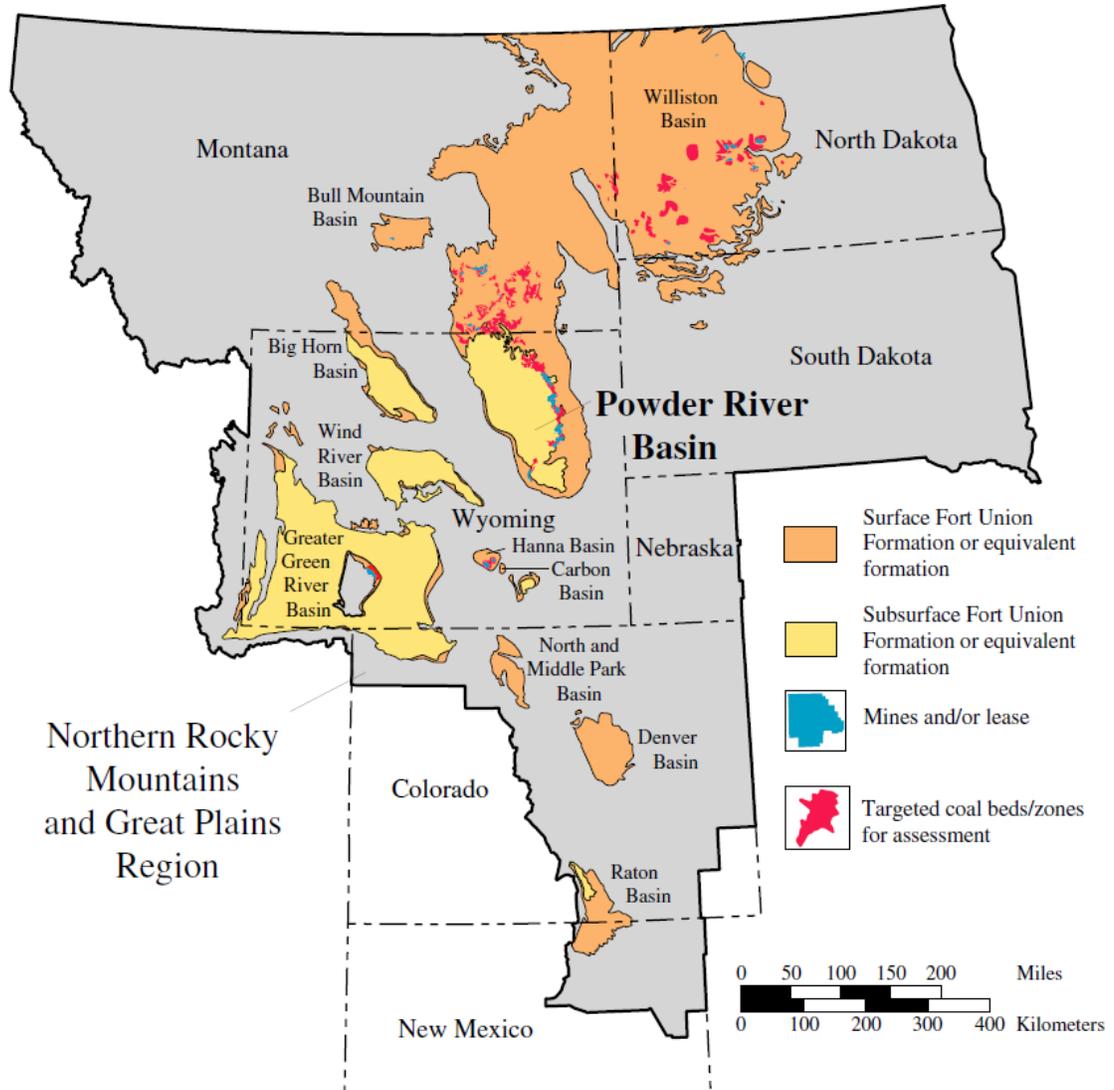
<http://fragis.frasafety.net/GISFRASafety/>.

B. Definition

Powder River Basin Coal. Coal mined from Powder River Basin (PRB) coal deposits found in southeast Montana and Northeast Wyoming (see map). PRB coal is classified as sub-bituminous, containing approximately 8,500 btu/lb, with low sulfur content relative to other coal sources. The table below compares characteristics and constituents of PRB Coal to Indiana Coal.

	Indiana coal	PRB coal
Moisture	10 -12%	~ 28%
Volatile matter	~ 40%	higher
Heating value	11,386 Btu/lb	Btu/lb 8,088
Ash content	9.4%	7.6%
AFT (flow, Reduction)	Need more data	?
Slag viscosity ~1400°C	Need more data	?
Char reactivity	Very few data Less reactive (higher T needed?)	More reactive because of more volatiles?
Sulfur	3.13%	0.72%
Chlorine	0.05%	0.01%

Source: M. Mastalerz, A. Drobniak, J. Rupp and N. Shaffer, "Assessment of the Quality of Indiana coal for Integrated Gasification Combined Cycle Performance (IGCC)," Indiana Geological Survey, Indiana University, June 2005



C. Characteristics

Coal is a heterogeneous material and varies widely in texture and content of water, carbon, organic compounds and mineral impurities. Among its constituents are such potential toxicants as polycyclic aromatic hydrocarbons (PAHs) and trace metals/metalloids. Due to coal's relatively low specific gravity compared to most sediment particles, transport by water movement may result in larger particles of coal being transported and deposited with smaller, denser particles of sands and gravels. Settling times and, therefore, transport distances will also be greater for a given particle size.

When present in marine environments in sufficient quantities, coal will have physical effects on organisms similar to those of other suspended or deposited sediments. These include abrasion, smothering, alteration of

sediment texture and stability, reduced availability of light, and clogging of respiratory and feeding organs. Such effects are relatively well documented.

It is less clear whether organic compounds in coal can leach out into aqueous solution at concentrations that would cause concern from the perspective of potential biological effects. A fairly lengthy study sponsored by the USEPA (Carlson et al., 1979) used both Lake Superior water and purified water to create coal leachate solutions, but the concentrations of individual PAHs was less than 10-50 ng/L (parts per trillion). The predominant PAH types that solubilized were lower weight and alkylated PAHs, but the resulting equilibrium concentrations were equivalent to background levels in Lake Superior water. According to an environmental chemist with experience in distinguishing sources of PAHs in the marine environment, the tenacity with which PAHs are retained by coal can be explained by its physical structure:

Coal often carries a petrogenic (oil-sourced) PAH signature that can be partially extracted on exposure to aggressive organic solvents like dichloromethane, but they are not bioavailable because they are sequestered within the mostly crystalline carbon matrix of coal. Consequently, the PAH signature contains abundant proportions of labile species like naphthalene that persist over geologic time scales in sediments
(Jeffrey Short, JWS Consulting, LLC, pers. comm., 5 February 2013).

Toxic effects of contaminants in coal are much less evident, highly dependent on coal composition, and in many situations their bioavailability appears to be low. Bender et al. (1987) studied the uptake of hydrocarbons from coal in oysters and found virtually no increase in tissue burdens and no effect of even the highest exposure on shell growth. Chapman et al. (1996) studied the availability of coal dumped near Victoria (B.C.) harbor in 1891 and also reviewed the literature for effects of coal on aquatic organisms, and in both cases found little effect. Nevertheless, the presence of contaminants at high concentrations in some coal leachates and the demonstration of biological uptake of coal-derived contaminants in a small number of studies suggest that this may not always be the case, a situation that might be expected from coal's heterogeneous chemical composition; and recently, a noted NOAA toxicologist studying the biochemistry of oil hydrocarbons expressed concerns about the potential for biological effects from similar coal hydrocarbons. There are, however, surprisingly few studies in the marine environment focusing on toxic effects of contaminants of coal at organism-, population- or assemblage-levels. Campbell et al. (1997) found that juvenile Chinook salmon exposed to coal dust experienced elevated induction of CYP1a1, a gene encoding the xenobiotic metabolizing cytochrome P450 enzyme—but the implications of this to the health of the fish were not determined. The limited evidence indicating bioavailability of coal hydrocarbons under certain circumstances suggests that more detailed studies would be prudent, particularly with the Powder River product

expected to be transported through the Pacific Northwest and under conditions of exposure relevant to our region.

Beyond the potential for uptake and effect of hydrocarbons in coal, another environmental concern may be the elevated levels of metals that are found in association with coal. While emissions from coal burning and coal fly ash have been well documented as sources of elevated trace metals into the air and soil, less information is available about the metal content of processed coal and the potential environmental implications from those metals. Struempfer and Jolley (1979) measured trace metals in samples of Wyoming coal from the Fort Union and Hannah Formations (refer to figure above). For eleven Fort Union Formation coal samples, average concentrations (in parts per million) of metals were as follows:

Al = 6,700; Na = 780; K = 520; Mn = 41; Zn = 38; Cu = 21; Co = 4.1; Pb = 5.6; Cd = 0.43; Ag = 0.5; Tl = <0.5.

Bounds and Johannesson (2007) analyzed soil samples near the largest coal terminal in the northern hemisphere, located in Norfolk, VA. They found arsenic concentrations in soil samples and coal extracted from soil that ranged as high as 30.5 and 17.4 mg/kg (ppm), respectively. They concluded that risks from coal itself were likely minor, but environmental consequences of arsenic associated with the coal were not known.

As with the PAHs, it is not clear if or to what extent trace elements in coal are biologically available to potentially exposed organisms. As a result, the significance of concentrations of metals or other elements that occur with coal at naturally enriched levels is uncertain. Coal dust escapement and rainwater leachate from coal cars can be expected along rail corridors in the Northwest and at transfer terminals, and it is likely that concentrations of metals will be elevated in these areas (<http://www.epa.gov/cleanenergy/energy-and-you/affect/coal.html>).

A similar situation was documented in the latter part of the twentieth century along U.S highways and interstates, in which environmental concentrations of lead were found along the lengths of the roadways due to lead anti-knock additives in gasoline (since banned). However—whether the higher concentrations of metals that might result from coal transport by rail can be considered as environmental risks remains to be determined.

In the paper titled “Juvenile Salmonid Use of Habitats Altered by a Coal Port in the Fraser River Estuary, British Columbia,” C.D. Levings (Marine Pollution Bulletin, Volume, 16) describes alteration of habitat and diversion of Salmonid migration via an associated causeway due to impacts of coal terminal development.

The PAH content of coals is summarized in the table below. Powder River Basin coal would compare most directly to the Wyodak, USA, and possibly to other listed highly volatile, sub-bituminous entries.

Table 1 – Summary of total and 16 EPA polycyclic aromatic hydrocarbon concentrations in coals			
	Total PAHs [mg/kg]	EPA-PAHs [mg/kg]	References
High volatile bituminous coal A, Elmsworth gasfield, 10-11-71-11W6, Canada	2429.1	152.1	
High volatile bituminous coal A, Elmsworth gasfield, 10-03-70-10W6, Canada	2412.3	136.6	
Medium volatile bituminous coal, Ruhr basin, Osterfeld, Germany	1037.2	153.3	
Medium volatile bituminous coal, Ruhr basin, Hugo, Germany	933.8	123.6	
Low volatile bituminous coal, Ruhr basin, Westerholt, Germany	1200.7	163.9	
Low volatile bituminous coal, Ruhr basin, Blumenhal, Germany	786.5	155.4	Willsch and Radke (1995)
Low volatile bituminous coal, Elmsworth gasfield, 06-19-68-13W6, Canada	546.4	98.6	
Low volatile bituminous coal, Ruhr basin, Haard, Germany	567.7	154.8	
High volatile bituminous coal, Wealden Basin, Nesselberg, Germany	656.2	43.1	
High volatile bituminous coal, Wealden Basin, Barsinghausen, Germany	554.4	56.7	Radke et al. (1990)
High volatile bituminous coal, Saar, Ensdorf, Germany	165.9	50.5	
Medium volatile bituminous coal, Germany	68.0	22.4	
Bituminous coal, Germany	127.6	28.7	Pies et al. (2007)
Lignite A, Northern Great Plains, Beulah, USA	8.5 ^a	1.2	
Lignite A, Northern Great Plains, Pust, USA	6.5 ^a	1.0	
Sub-bituminous coal C, Northern Great Plains, Smith-Roland, USA	12.0 ^a	0.1	
Sub-bituminous coal C, Gulf Coast, Bottom, USA	14.0 ^a	1.6	
Sub-bituminous coal B, Northern Great Plains, Dietz, USA	14.0 ^a	0.8	
Sub-bituminous coal B, Northern Great Plains, Wyodak, USA	5.4 ^a	0.3	
Sub-bituminous coal A, Rocky Mountains, Deadman, USA	12.0 ^a	1.5	
High volatile bituminous coal C, Rocky Mountains, Blue, USA	77.0 ^a	5.3	
High volatile bituminous coal B, Eastern Coal, Ohio #4A, USA	60.0 ^a	8.2	
High volatile bituminous coal A, Rocky Mountains, Blind Canyon, USA	78.0 ^a	4.4	
High volatile bituminous coal A, Eastern Coal, Pittsburgh, USA	76.0 ^a	11.0	Stout and Emsbo-Mattingly (2008)
Medium volatile bituminous coal, Rocky Mountains, Coal Basin M, USA	29.0 ^a	1.8	
Low volatile bituminous coal, Eastern Coal, Pocahontas #3, USA	20.0 ^a	3.8	
Semianthracite, Eastern Coal, PA Semi-Anth. C, USA	5.9 ^a	2.1	
Anthracite, Eastern Coal, Lykens Valley #2, USA	0.2 ^a	<0.1	
High volatile bituminous coal, Blind Canyon, USA	78.3	–	Stout et al. (2002b)
High volatile bituminous coal C-1, USA	7.5	0.5	
High volatile bituminous coal C-2, USA	3.4	0.4	
High volatile bituminous coal C-3, USA	2.4	0.3	
High volatile bituminous coal B-1, USA	1.6	0.3	
High volatile bituminous coal B-2, USA	12.7	2.4	
High volatile bituminous coal A-1, USA	13.7	5.4	Zhao et al. (2000)
High volatile bituminous coal A-2, USA	27.6	6.4	
Low volatile bituminous coal, USA	1.2	0.3	
Anthracite, China	2.5	1.8	Chen et al. (2004)
Bituminous coal, Brazil	13.0	–	Püttmann (1988)

^a Sum of 43 PAHS.

From: Native polycyclic aromatic hydrocarbons (PAH) in coals – A hardly recognized source of environmental contamination by C. Achten, and T. Hofmann, Science in the Total Environment, Elsevier B.V., 2008.

Summary table providing detailed analysis (n >150, depending on characteristic) of trace metals and other constituents in one coal zone of the Powder River Basin.

Table PQ-1. Summary data for coal in the Wyodak-Anderson coal zone in the Powder River Basin, Wyoming and Montana. Calculated from the unpublished U.S. Geological Survey coal quality database (USCHEM), February, 1992; Bragg and others (1994); and proprietary source(s)

Variable	Number of samples	Range		Mean
		Minimum	Maximum	
Moisture ¹	300	14.50	42.30	27.66
Ash ¹	279	2.86	25.06	6.44
Total sulfur ¹	279	0.06	2.40	0.48
Calorific value ²	277	3,740	9,950	8,220
lb SO ₂ ³	277	0.14	7.88	1.24
MMMFbtu ⁴	277	4,580	10,560	8,820
Antimony ⁵	144	0.01L	17	0.49
Arsenic ⁵	158	0.20L	19	2.6
Beryllium ⁵	151	0.078L	3.3	0.54
Cadmium ⁵	151	0.007L	3.0	0.21
Chromium ⁵	161	0.59L	50	6.1
Cobalt ⁵	160	0.38L	27	1.9
Lead ⁵	162	0.50L	17	3.0
Manganese ⁵	161	0.18	210	26
Mercury ⁵	162	0.006L	27	0.13
Nickel ⁵	161	0.71L	35	4.6
Selenium ⁵	151	0.08L	16	1.1
Uranium ⁵	157	0.11L	12	1.3

¹ Values are in percent and on an as-received basis.

² Value is in British thermal units (Btu).

³ Value is in pounds per million Btu and on an as-received basis.

⁴ Value is in British thermal units on a moist, mineral-matter-free basis.

⁵ Values are in parts per million (ppm) on a whole-coal and remnant moisture basis; "L" denotes less than value shown.

From: Coal Quality and Geochemistry, Powder River Basin, Wyoming and Montana by G.D. Stricker and M.S. Ellis in U.S. Geological Survey Professional Paper 1625-A: 1999 Resource Assessment of selected Tertiary coal beds and zones in the Northern Rocky Mountains and Great Plains region.

Regulatory Framework

Under U.S. Federal Regulations, coal is listed on the Toxic Substance Control Inventory. However, there is no CERCLA Reportable Quantity and it is not a listed waste under the Resource Conservation and Recovery Act (RCRA). As a solid waste, spilled coal would need to be characterized and a hazardous waste determination would need to be performed to determine whether RCRA is applicable. Coal is not considered an Extremely Hazardous Substance under SARA (Superfund Amendments and Reauthorization Act) TITLE III, Section 302.

The state environmental regulatory agencies consider spilled coal to be a solid waste, and potentially a hazardous waste depending on the presence of hazardous constituents. Available information on Powder River Basin coal does not indicate that hazardous constituents would be present in concentrations that would trigger designation as a hazardous waste if spilled, but that determination would need to be based on laboratory analyses of the source materials being transported, or through characterization of the waste itself.

The spillage of coal to land within the states would, at a minimum, trigger the need to characterize and clean up the wastes under state solid waste regulations. The spillage of coal into state waters, or into adjacent land area that could impact water quality would be a violation of water quality regulations and would necessitate immediate reporting to the appropriate state environmental agencies.

D. Response strategies

Appropriate response strategies for spills of coal will depend on the location of the spill, the environment the spill occurs in, and the media directly and indirectly impacted. All routes of transport or exposure, along with safety and occupational health concerns, need to be considered in site stabilization and cleanup efforts.

Response and cleanup of spilled coal would need to be coordinated with federal and state environmental agencies to make sure cleanup efforts do not further harm land or aquatic habitats, and to protect public health and the environment. Emergency authorizations and permits may be required to complete assessment and cleanup, and in some cases, the decision to delay or postpone these actions may be made to protect sensitive habitats. The NW Area Contingency Plan has resources to identify necessary permits and authorizations and the regulatory agencies administering them.

Collected wastes from the cleanup of spilled coal would need to be characterized and managed appropriately and disposed at an approved solid or hazardous waste facility, as indicated by the waste determination.

E. Safety issues

Coal handling and transport present unique challenges with respect to safety and protection of public and responder health. Risks of ignition, explosion, spontaneous combustion, the ability to create oxygen-poor environments, and the potential for dusts to create respiratory hazards must all be considered during routine material handling and spills alike. Although some elements of this topic are already covered in the Hazardous Materials and Marine Firefighting Sections of the Northwest Area Contingency Plan, the degree to which coal-specific safety elements are incorporated has not been evaluated by the task force. The integration of this information into local emergency management plans, or facility response plans also has not been evaluated.

From: Fire-protection guidelines for handling and storing PRB coal by Edward B. Douberly, Utility FPE Group, Inc.

Properties of typical firefighting agents

Agent	Properties
Water	Water can be effective at fighting PRB coal fires. However, water alone is not recommended. The surface tension of water does not allow it to penetrate deep below the coal's surface and reach the fire unless large quantities are injected. Large quantities of water inside a bunker or silo will ruin the coal inventory and may place additional loading on structural members.
Wetting agents	Wetting agents allow water to penetrate Class A material by reducing the surface tension of the water. They extinguish by cooling.
Foams	Foams contain a wetting agent that acts as the carrier of the foam. The primary function of foams is to blanket the fuel's surface, thereby reducing the oxygen supply. Foams are not very effective on coal fires due to the length of time it takes to smother a coal fire and the need to keep the foam blanket in place. Mechanical foams also tend to break down and dissipate before the fire is completely out. Deep-seated Class A fires cannot be effectively extinguished with foams. Foams that pass UL Fire Performance Criteria are Class B. Foams that do not pass the test are classified as Class A and do not meet any usage criteria other than the manufacturer's own recommendations.
Micelle-encapsulating agents	These agents, when used with water, are the extinguishing media of choice for PRB coal fires and for flammable liquids fires (Class A and B fires). These agents have the following three suppression mechanics: <ul style="list-style-type: none"> ▪ Micelle formation. On Class B fires, the agents encapsulate both the liquid and vapor phase molecules of the fuel and immediately render them nonflammable. ▪ Surface tension reduction. The agents reduce the surface tension of water from 72 dynes/cm² to less than 30 dynes/cm². This action provides up to a 1,000% increase in the wetted area, compared with using water alone. ▪ Free radical interruption. The agents interrupt the free radical chain reaction of the fire tetrahedron. For this application, they are governed by NFPA 18 and are listed for both Class A and Class B usage. Agents can be used effectively on coal fires at concentrations of 0.5% to 1.0%.
Other agents	Gases such as CO ₂ and N ₂ have been tried as fire-suppression agents but have not proven effective. Reasons include their poor cooling capacity and their general inability to maintain proper concentration levels in bunkers and silos. Accordingly, these agents require extended use—for hours or even days—depending on the quantity of the coal burning and the complexity of the fire. Independent testing has shown that the effectiveness of gases is a function of fuel geometry, the stage of the fire, the tightness of the enclosure, and the duration of application.

Source: Utility FPE Group Inc.

V. CONCLUSIONS

Although coal transport is not new to the Pacific Northwest, the dramatic increase in the amount of Powder River Basin coal transport presents new risks and challenges to emergency planning and response.

There is a general lack of information regarding the impacts of coal when spilled to the environment, and even limited information on the makeup and characteristics of coal originating from the Powder River Basin. The lack of information on constituents and characteristics of the PRB coals and their effects on the environment when spilled will complicate response and delay or impede characterization and cleanup efforts.

Though there is limited available information on the toxicity of coal constituents in freshwater and marine environments, the physical impacts of coal particles (especially dusts on land and suspended fine sediments in aqueous environments) represent risks to these environments that must be addressed if spilled, and will present challenges to the response and cleanup efforts.

The unique firefighting and safety issues surrounding coal are substantial and well documented in the literature but may be less known to local responders in areas where coal transportation has dramatically increased. The impacts of transportation and safety issues have likely not been incorporated into local emergency planning efforts.

VI. RECOMMENDATIONS

The Emerging Risks Task Force recommends that the Northwest Area Committee and its participants:

- Continue to watch developments in the push to develop new terminal projects and the corresponding increase in rail and vessel transport. This should include monitoring the Vessel Traffic Risk Assessment as one way to gauge the increase in risk for the Northwest.
- Continue to gather, analyze, and distribute information relative to the response to spills of coal in the Northwest. In particular, detailed analysis of the constituents that make up Powder River Basin coal, and their effects on potentially impacted environments need to be available prior to the event of spills in order to streamline response.
- Support research to better understand the environmental consequences of Powder River Basin coal introduced into the aquatic and marine environments of the Northwest, specifically, whether contaminants associated with the coal (PAHs, metals, trace elements) are biologically available under conditions reasonably expected to be encountered in our region.

- Synthesize and incorporate information on response safety and appropriate measures to increase responder and public health and safety into appropriate chapters of the NW Area Contingency Plan, and make that information available for incorporation into local emergency management plans. Evaluate facility response plans to make sure appropriate safety information is available and consistent with the NW Area Contingency Plan.

COAL EFFECTS REFERENCES

Ahrens, M.J. and D.J. Morrissey. 2005. Biological effects of unburnt coal in the marine environment. *Oceanography and Marine Biology: An Annual Review* 43:69-122.

Bender, M.E., M.H. Roberts Jr., and P.O. deFur. 1987. Unavailability of polynuclear aromatic hydrocarbons from coal particles to the eastern oyster. *Environmental Pollution* 44(4): 243-260.

Bounds, W.J. and K.H. Johannesson. 2007. Arsenic addition to soils from airborne coal dust originating at a major coal-shipping terminal. *Water, Air, and Soil Pollution* 185(1-4): 195-207.

Campbell, P.M. and R.H. Devlin. 1997. Increased CYP1a1 and ribosomal protein L5 gene expression in a teleost: The response of juvenile Chinook salmon to coal dust. *Aquatic Toxicology* 38:1-15.

Carlson, R.M., A.R. Oyler, E.H. Gerhart, R. Caple, K.J. Welch, H.L. Kopperman, D. Bodenner, and D. Swanson. 1979. Implications to the aquatic environment of polynuclear aromatic hydrocarbons liberated from Northern Great Plains coal. Report EPA-600/3-79-093. Duluth MN: Environmental Research Laboratory, USEPA. 156 pp.

Chapman, P.M., J. Downie, A. Maynard, and L.A. Taylor. 1996. Coal and deodorizer residues in marine sediments—contaminants or pollutants? *Environmental Toxicology and Chemistry* 15(5): 638-642.

Drever, J.I., J. W. Murphy, and R. C. Surdam. 1977. The distribution of As, Be, Cd, Cu, Hg, Mo, Pb, and U associated with the Wyoak coal seam, Powder River basin, Wyoming. *Rocky Mountain Geology* 15:93-101.

Hillaby, B.A. 1981. The effect of coal dust on ventilation and oxygen consumption in the Dungeness crab *Cancer magister*. *Can. Tech. Rep. Fish. Aquat. Sci.* 1033.

Johnson, R. and R.M. Bustin. 2006. Coal dust dispersal around a marine coal terminal (1977-1999), British Columbia: The fate of coal dust in the marine environment, *International Journal of Coal Geology* 68:57-69.

Mangena, S.J. and A.C. Brent. 2006. Application of a life cycle impact assessment framework to evaluate and compare environmental performances with economic values of supplied coal products. *Journal of Cleaner Production* 14(12-13): 1071-1084.

Murphy, T., A. Moller, and H. Brouwer. 1995. In situ treatment of Hamilton Harbour sediment. *Journal of Aquatic Ecosystem Health* 4:195-203.

Naidoo, G. and D. Chirkoot. 2004. The effects of coal dust on photosynthetic performance of the mangrove, *Avicennia marina* in Richards Bay, South Africa. *Environmental Pollution* 127:359-366.

Short, J.W., J.J. Kolak, J.R. Payne, and G.K. Van Kooten. 2007. An evaluation of petrogenic hydrocarbons in northern Gulf of Alaska continental shelf sediments — The role of coastal oil seep inputs. 2007. *Organic Geochemistry* 38: 643-670.

Struempfer, A.W. and J.M. Jolley. 1979. Trace metals in Wyoming coal: Their analysis, concentrations and interrelationships. *Transactions of the Nebraska Academy of Sciences VII: 87-90.*

Voparil, I.M., R.M. Burgess, L.M. Mayer, R. Tien, M.G. Cantwell, and S.A. Ryba. 2004. Digestive bioavailability to a deposit feeder (*Arenicola marina*) of polycyclic aromatic hydrocarbons associated with anthropogenic particles. *Environmental Toxicology and Chemistry* 23(11): 2618-2626.

Yunker, M.B., A. Perreault, and C.J. Lowe. 2012. Source apportionment of elevated PAH concentrations in sediments near marine outfalls in Esquimalt and Victoria, BC, Canada: Is coal from an 1891 shipwreck the source? *Organic Geochemistry* 46: 12-37.

VII. FINDINGS: HEAVY FUEL OILS OR NONFLOATING OILS

A. Transportation picture

From 1991 to 1996, approximately 17 percent of the petroleum products transported over U.S. waters were heavy oils and heavy-oil products, such as residual fuel oils, coke, and asphalt. Approximately 44 percent was moved by barge and 56 percent by tanker. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

From 1991 to 1996, approximately 23 percent of the petroleum products spilled in U.S. waters were heavy oils. In only 20 percent of these spills did

a significant portion of the spilled products sink or become suspended in the water column. Most of the time, spills of heavy oil remained on the surface. The average number of spills of more than 20 barrels of heavy oil and asphalt was 16 per year, with an average volume of 785 barrels per spill. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

In calendar year 2011, the five refineries in the [Pacific Northwest] region shipped 2.25 million barrels of <10 API gravity oil [heavy oil] in 41 vessel transits both by ship and barge. (Frank Holmes, WSPA, 2013 email) The five refineries: BP's Cherry Point Refinery (Ferndale, Wash.), Phillips 66 Refinery (Ferndale, Wash.), Tesoro Refinery (Anacortes, Wash.), Shell Refinery, (Anacortes, Wash.), and US Oil Refinery, (Tacoma, Wash.)

These over-the-water transports can trigger federal / state regulations which require Facilities, Vessels and Oil Spill Response Organizations (OSROs) <http://www.uscg.mil/hq/nswfweb/nsf/nsfcc/ops/ResponseSupport/RAB/osroclassifiedguidelines.asp> to have additional equipment in their inventories to locate, contain and remove sunken [heavy] oil. See Vessel (33 CFR §155.1052 & Facility (33 CFR §154.1047) regulations. If a facility or vessel handles [heavy] Group V oil as a primary cargo, it must be called out clearly in their response plans and identify OSROs that have equipment to detect, contain and recover Group V oil. Within the Sector Puget Sound zone four, OSROs have identified themselves as having Group V capabilities. They are Marine Spill Response Corporation, National Response Corporation, Marine Pollution Control Corporation and Oil MOP Incorporated. Within the Sector Columbia River zone four, OSROs have identified themselves as having Group V capabilities. They are Marine Spill Response Corporation, National Response Corporation, Clean Harbors Environmental Services and Oil MOP Incorporated. <https://cgrri.uscg.mil/UserReports/WebClassificationReport.aspx>

OSROs self-certify that they have Group V [heavy oil] response capability by checking a box in the USCG National Strike Force (NSF) Response Resource Inventory (RRI) database. According to the National Strike Force Coordination Center, the CG RRI program has no programming in the system to validate these claims. Nor are these capabilities specifically targeted or confirmed during Port Area Visits by the USCG National Strike Force teams in the field conducting equipment verifications. In the lessons learned from the 2007 paper on the Tank Barge DBL, 152 author's note: "The current OSRO classification system and Vessel Response Plan review process do not validate the OSRO or owner/operators' ability to respond to a Group V oil spill. As a result, the nation's ability to respond to Group V remains unknown." (Elliott, et al., 2007) Self-certification without verification certainly calls for further discussion.

B. Definition

Group V Oils.

Oils in our Area of Responsibility (AOR) that represent the threat of sinking or are classified as Group V oils (Per 33 CFR 155.1020 - Definition Group V oil – One that has a specific gravity greater than 1.0.)

Specific gravity, as used in the regulatory definition of Group V oils, does not adequately characterize all oil types and weathering conditions that produce nonfloating oils. In addressing the issue of responses to Group V oil spills, defined by current regulations as oils with a specific gravity of greater than 1.0, the issue of concern is planning for and responding to oil spills in which most, or a significant quantity, of the spilled oil does not float. Some, therefore, may use the term “nonfloating oils” to describe the oils of concern. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

In Coast Guard District 13 / EPA Region 10, sinking oils are found in Group V Residual Fuel Oils (GPVRFO), known by the industry term “LAPIO” (Low API Oil), including Asphalt and Asphalt Products. Additional terms that can identify potentially sinking oils include No. 6 oil, Bunker C, heavy cycle gas oil, slurry oil or residual fractions, coal tar oil, carbon black feedstock and residual bottoms. There are small quantities of Residual Fuel Oil, just under a two-gallon yield, from each barrel of crude oil refined. (American Petroleum Institute (API))

New regulations in the state of Washington require a thorough description in oil spill plans concerning the types and characteristics of oils handled by the facility, vessel and pipeline companies. This includes both the API gravity and oil classification group. This will aid in the planning for responses within the Northwest community. The state has also adopted the federal standard for Group V oil equipment and requires that the assets be located locally.

C. Characteristics

“Heavy oil” is the term used by the response community to describe dense, viscous oils with the following general characteristics: low volatility (flash point higher than 65°C), very little loss by evaporation, and a viscous to semi-solid consistency (NOAA and API, 1995).

The term “nonfloating oil” is used to describe all oils that do not float on water, including oils that are denser than the receiving waters and either sink immediately or mix into the water column and move with the water as suspended oil; as well as the portion of oil that is initially buoyant but sinks after interacting with wind or waves. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Nonfloating oils move below the sea surface either because of their initial densities or because of changes in their densities as a result of weathering or interaction with

sediments. These oils may be just below the water surface, suspended in the water column, or deposited on the seabed. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

The Nestucca Spill in December 1988 released 5,500 barrels of heavy marine fuel oil with an API gravity of 12.1 three kilometers off Grays Harbor, Wash. The spilled oil quickly formed tar balls that moved below the water surface (i.e., were overwashed by waves) and could not be tracked visually. Two weeks later, oil unexpectedly came ashore along the coast of Vancouver Island, Canada, 175 kilometers north of the release site, contaminating 150 kilometers of shoreline (NOAA, 1992).

D. Response strategies

There are a number of subcontractors connected to OSROs that provide niche expertise when it comes to detecting, containing and recovering sinking oils. They include but are not limited to local companies such as Manson Construction, Global Diving and Salvage, NW Underwater Construction, Fred Devine Diving and Salvage, Anchor Environmental and Hickey Marine. Nationally, major salvage companies such as T&T Marine Salvage have additional resources for detecting and recovering submerged oil.

Within the District 13 AOR, the expectation of the Co-chairs of the Area Committee and committee members is that Group V oil will be identified in the initial report of an oil spill to the National Response Center. Also, communication of the potential for sinking oil must again be brought to the attention of the Unified Command at the Initial UC Meeting. With knowledge that oil spilled is Group V, professional oil spill responders will identify specialized submerged oil equipment / personnel and get it on-scene. Unified Commanders must concern themselves with writing response objectives aimed at underwater detection, containment and recovery. The Operations Section will meet these objectives by developing detection strategies potentially using sonar, divers / cameras, ROV / camera, aircraft, photo bathymetry, diaper drops, dragnet, snare drops, and side-scan sonar. Containment strategies consist of using bubble curtains, water jets, surface-to-bottom nets/screens, silt curtain, and natural collection sites. Recovery strategies consist of using diver directed oil recovery operations, remotely operated vehicles, dredges, vacuum systems, integrated video mapping systems, nets, sorbents, bioremediation and pre-spill surveys. The difficulty in ramping up to detect and recover Group V oils in the water column or on the sea bottom is no small logistical / operational matter.

Within the District, there are a number of companies that are experienced with surface-supplied and saturation diving; but in general, above the minimum requirements of the CFRs, there is a not an extensive stockpile of submerged equipment resident in our region. Some of the more unique equipment is not resident and will have to be cascaded in from outside the

region. Knowledge of and the decisions to mobilize specific equipment and personnel early from across the continent will be essential to waging an aggressive cleanup campaign. Specifically, detection equipment for sinking oil can be proprietary as it is an evolving technology.

The Incident Command System has the flexibility to expand to incorporate Sinking Oil Detection Groups, Sinking Oil Recovery Groups and Sinking Oil Divisions; however, no management system can be successful without awareness, planning and exercising beforehand.

Although spill modeling and supporting information systems are well developed, they are not commonly used in response to nonfloating-oil spills because of limited environmental data and observations of oil suspended in the water or deposited on the seabed. Oil-spill models and supporting information systems are routinely used in contingency planning and spill responses. Sophisticated, user-friendly interfaces have been developed to take advantage of the latest advances in computer hardware and software. The current generation of models can rapidly incorporate environmental data from a variety of sources and include integrated geographic information systems. The models can also assimilate data on the most recently observed location of spilled oil and have improved forecasts of oil movements. They are not routinely used, however, in response to nonfloating oil spills because of the lack of supporting data on three-dimensional currents and concentrations of suspended sediments. Field data, such as oil concentrations in the water column and on the seabed, are also not generally available to validate or update models. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Although a number of techniques and tools for tracking subsurface oil have been developed, most have not been used in response to actual oil spills. Many techniques are available for determining the location of oil both in the water column and on the seabed. These include visual observations, geophysical and acoustic methods, remote sensing, water-column and seabed sampling, *in situ* detectors, and nets and trawl sampling. The most direct and simplest methods, such as diver observations and direct sampling, are widely used, but they are labor intensive and slow. More sophisticated approaches, such as remote sensing, are limited to zones very near the sea surface because of technical constraints. Other advanced technologies, such as acoustic techniques, cannot differentiate between oil and water or between oiled sediments and underlying sediments. Many of the more sophisticated systems are prone to misuse and produce ambiguous data that are subject to misinterpretation. The performance of all but the simplest methods is undocumented either by field experiments or by use in spill responses. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

Technologies are available for containing and recovering subsurface oil, but few are effective and most work only in very limited environmental conditions. Containment of oil suspended in the water column using silt curtains, pneumatic barriers, and nets and trawls is only effective in areas with very low currents and minimal wave activity. These conditions rarely exist at spill sites, particularly at sites in estuarine or coastal waters. The recovery of oil in the water column by trawls and nets is limited by the viscosity of the oil and net tow speeds. The containment of oil on the seabed is typically ineffective, except at natural collection points (e.g., depressions and areas of convergence). The collection of oil on the seabed by manual methods, in natural collection areas and along the shoreline after beaching, is effective but labor intensive and slow. Manual methods are also limited by the depths at which diver-based operations can be carried out safely. Dredging techniques have rarely been used because of limited recovery rates, the large volumes of water and sediment generated, and the problems of storing, treating, and discharging co-produced materials. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

The lack of knowledge and lack of experience, especially at the local level, in responding to spills of nonfloating oils is a significant barrier to effective response. The knowledge base and response capabilities for tracking, containing, and recovering nonfloating oils have not been adequately developed. Even at the national level, no system has been developed for sharing experiences or documenting the effectiveness and limitations of various options. With limited experience and a lack of proven, specialized systems, responders have found it difficult to adapt available equipment for responses to spills of nonfloating oils. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

E. Safety issues

Nonfloating oils behave differently and have different environmental fates and effects from floating oils. The resources at greatest risk from spills of floating oils are those that use the water surface and the shoreline. Floating-oil spills seldom have significant impacts on water-column and benthic resources. In contrast, nonfloating-oil spills pose a substantial threat to water-column and benthic resources, particularly where significant amounts of oil have accumulated on the seafloor. Nonfloating oils tend to weather slowly and thus can affect resources for long periods of time and at great distances from the release site. All told, the effects and behavior of nonfloating oil are poorly understood. (Spills of Nonfloating Oils: Risk and Response / National Research Council)

In general, a commercial diving operation inspection consists of three phases: (1) Personnel, (2) Operations, and (3) Equipment. The OSHA and Coast Guard regulations are similar in scope; however, additional requirements apply when conducting operations from vessels that require a

Coast Guard certificate of inspection. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

If the commercial diving contractor wishes to deviate from the USCG requirements, the contractor must submit a variance request in writing to Coast Guard Headquarters via the local Marine Safety Office. A copy of all approved variances must be available at the dive location or aboard the dive support vessel before commencing diving operations. OSHA does not permit deviations from their diving standards. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

When diving operations are conducted in contaminated water or in an area where there is a substantial threat of discharge of oil or hazardous materials, commercial divers must also comply with the OSHA training and operational standards for Hazardous Waste Operations and Emergency Response (HAZWOPER). Divers should provide proof of HAZWOPER training, and evidence that they have completed the annual refresher training, before commencing diving operations. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

Diving in contaminated water requires equipment that protects divers from pollutants. As a rule, if the pollutant is unknown, diving operations should not be permitted. With the exception of the requirement to comply with the HAZWOPER standards, to date, the U.S. Coast Guard, OSHA, and the International Maritime Organization have not published regulations that mandate specific equipment or training for diving in contaminated water. However, the National Research Council (NRC), U.S. Environmental Protection Agency (EPA), and the National Oceanic and Atmospheric Administration (NOAA) have published guidance and protocols. Additionally, the Association of Diving Contractors (ADC) has drafted industry standards for contaminated water diving that are now under review by the members of the association. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

The NRC's report on spills of nonfloating oils recommends operational limitations for diving in contaminated waters to depths of 20 meters, a minimum visibility of 0.5 to 1.0 meter, and low-water currents (NRC, 1999). However, existing OSHA and USCG regulations allow commercial divers to work in depths in excess of 60 meters, zero visibility, and heavy currents. Additionally, the ADC, EPA, and NOAA do not restrict commercial diving operations to depths that are more stringent than the

depth requirements noted in the regulatory checklist, nor do they mandate visibility and current-speed standards.

A review of historical submerged oil recovery case studies shows that commercial divers have safely and successfully completed operations in conditions that exceed the NRC's proposed operational limitations. For example, during the *T/B Apex 3512* oil recovery from the bottom of the lower Mississippi in 1995, divers worked in depths that exceeded 20 meters, "zero visibility and a strong downriver current" (Weems, et al, 1997). Divers encountered similar conditions during the winter of 1995 submerged coal tar recovery in the Detroit River (Helland, et al, 1997).

It should be noted that according to the EPA, equipment problems in contaminated water are caused primarily by petroleum products (Traver, 1986). Divers exposed to petroleum constituents often experience equipment failure and deterioration. For example, Purser and Kunz provide a case study where a diver was exposed to elevated levels of benzene: "The benzene weakened the rubber straps on his helmet, and his neck, face and head were well exposed to the benzene mixture for a few seconds." The diver was later hospitalized due to his brief exposure (Purser and Kunz, 1985). (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

To prevent these types of accidents, safety officers should supplement their site-specific safety plan and on-site safety audits with a safety checklist for contaminated water diving. (COMMERCIAL DIVING OPERATIONS DURING SALVAGE AND POLLUTION RESPONSE OPERATIONS, James E. Elliott)

VIII. CONCLUSIONS

A. The tracking, containment, and recovery of spills of nonfloating oils pose challenging problems, principally because nonfloating oils suspended in the water column become mixed with large volumes of seawater and may interact with sediments in the water column or on the seabed. The ability to track, contain, and recover nonfloating oils is critically dependent on the physical and chemical properties of the oils and the water or the oils and the other materials dispersed in the water column or on the seabed. The differences in these characteristics are often quite small, and little technology is available for determining them. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

B. Although many methods are available for tracking nonfloating oils, the simplest and most reliable are labor intensive and cover only limited areas. More sophisticated methods have severe technical limitations, require specialized equipment and highly skilled operators, or cannot distinguish oil from water or other materials dispersed in the water column. Engineered systems for containing oil in the water column or on the seabed are few and only work in environments

with low currents and minimal waves. Natural containment in seabed depressions or in the lee of topographical or man-made structures on the seabed is effective for containing oils, but these are not always present in the vicinity of the spill. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

C. The recovery of oil from the water column is very difficult because of the low concentration of dispersed oil; hence, recovery is rarely attempted. If oil collects on the seabed in natural containment areas, many options for effective recovery are available, although most of them are labor intensive and access to response equipment is a problem. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

D. The risks of potential harm to water-column and benthic resources from nonfloating oils have not been adequately addressed in the contingency plans for individual facilities or geographic areas. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

IX. RECOMMENDATIONS

The recommendations below are intended to improve the capability of the spill response community to respond to spills of nonfloating oils.

A. The Area Planning Committee must assess the risk of spills of nonfloating oils (i.e., oils that may be dispersed in the water column or ultimately sink to the seabed) to determine the resources at risk. In areas with significant environmental resources risk, the Area Planning Committee should develop response plans that include consultation and coordination protocols and should obtain pre-approvals and authorizations to facilitate responses to such spills. Stakeholder groups should be educated about the impact and methods available for tracking, containing, and recovering oil suspended in the water column or on the seabed. The Area Committee should include at least one scenario for responding to a nonfloating-oil spill in their training or drill programs. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

B. The Area Planning Committee must improve its knowledge base and training for responding to spills of nonfloating oils by including a scenario involving a spill of nonfloating oils in oil spill response drills, by establishing a knowledge base and scientific support teams to respond to these types of spills, and by disseminating this knowledge as part of ongoing training programs. The information would help area planners assess the requirements for responding to nonfloating-oil spills. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

C. The Area Planning Committee should support the development and implementation of an evaluation program for tracking oil in the water column and on the seabed, as well as containment and recovery techniques for use on the seabed. The findings of these evaluations should be documented and distributed to the environmental response community to improve response plans for spills of

nonfloating oils. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

D. Tests of area contingency plans and industry response plans for responses to spills of nonfloating oils should be required parts of training and drill programs. (Spills of Nonfloating Oils: Risk and Response/National Research Council)

E. Companies that transport sinking oils over the waters in D13 / Region 10 should expect Government-Initiated Unannounced Exercises with the specific objective of determining if they are prepared with the tools, strategies and tactics to carry out their companies' response plan with respect to sinking oils.

X. FINDINGS: LIQUID NATURAL GAS (LNG)

A. Transportation picture

On 1 August 2012, the North American Emission Control Area (ECA) as designated by the International Maritime Organization (IMO) went into effect. The ECA is intended to reduce air pollution and will impose enforceable limits on a variety of air emissions from vessels. In order to comply with these stricter emission standards, there has been a growing interest by the maritime industry in converting existing vessels and/or constructing new vessels to use LNG as fuel. The maritime industry is considering a variety of methods for supplying LNG to these LNG-fueled vessels. Such methods include, but are not limited to, LNG delivered from bunkering vessels, e.g., tank barges and small tankers), or via shore-based facilities, e.g., storage tanks in waterfront facilities, tank trucks, and rail tank cars.

Initially, few ports in the U.S. will have the infrastructure required for LNG vessels, but Seattle is on the leading edge of maritime usage and shore side distribution projects. Seattle can expect a potential increase in traffic as vessels shift to ports that have LNG refueling capability. There will be a variety of issues that this raises, including the fact that it could potentially reduce the oil outflow in the event of a casualty (e.g. LNG gets released and floats/evaporates). In addition, response plan holders should consider if new equipment is needed for an effective response. Industry comments indicate using LNG for fuel is one of the biggest revolutions in maritime transportation, not unlike going from sail to steam to fuel oil.

Proposed for Oregon. The state of Oregon is currently facing two proposals for LNG terminals, one in the Columbia River at Warrenton, and one in Coos Bay. The Warrenton proposal would be "bi-directional" with the ability to liquefy and export LNG as well as re-gasify and supply the interstate gas pipeline system during peak demands. The Coos Bay proposal is for liquefaction and export only. The pipeline for the Warrenton facility would tap into an existing gas pipeline near Woodland, Wash., requiring 80 miles of new pipeline. The pipeline supplying the Coos Bay proposal would tap into a hub near Malin, Ore., and will require 230 miles of new pipeline.

Oregon LNG's Proposal. Oregon LNG proposes to build an industrial complex on the Skipanon Peninsula, near the mouth of the Columbia River, primarily to liquefy and export LNG to Free-Trade-Agreement countries. The facility would also be equipped to re-gasify and feed gas into the interstate gas pipeline to level out peaks in demand. At peak production, 2 or 3 vessel visits each week could be expected. The proposal also includes 80 miles of new 36-inch pipeline from the facility, under the Columbia River near Deer Island, Ore., to join an existing pipeline on the I-5 corridor near Woodland, Wash.

Other information:

Dept. of Energy/Sandia National Laboratory conducted large-scale LNG pool fire experiments, which can be viewed at: https://web.ornl.gov/efcogWorkshop/Stirrup_presentation.pdf

USCG Headquarters has established a working group to provide guidance on safety, security and response concerns. The Dept. of Energy published a Notice of Intent to Prepare an Environmental Impact Statement for the Planned Magnolia (Louisiana) Liquefied Natural Gas Project in the Federal Register on June 25, 2013. In addition, IMO is also working to update LNG guidance.

B. Definition

Liquefied natural gas or LNG is natural gas (predominantly methane, CH₄) that has been converted to liquid form for ease of storage or transport. Liquefied natural gas takes up about 1/600th the volume of natural gas in the gaseous state. It is odorless, colorless, non-toxic and non-corrosive. Hazards include flammability after vaporization into a gaseous state, freezing and asphyxia. (Wikipedia)

C. Characteristics

LNG is made up of several hydrocarbon gases but mainly methane. This gas mixture is cooled until it condenses into a liquid form. The gas is extracted from the ground or produced as a by-product of oil or coal extraction, piped into liquefaction facilities, liquefied and piped onto LNG tankers. The LNG is then shipped overseas via tanker ship and delivered to import re-gasification terminals. At these import re-gasification terminals, the liquid is heated to return to its gaseous form and piped into pipelines to be delivered to the pipeline grid.

D. Response strategies / E. Safety issues

Controllable Emergency - This is an emergency in which the Terminal Operations Personnel can prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment, or initiating the Emergency Shutdown System. (Oregon LNG, Emergency Response Manual)

Uncontrollable Emergency - This is an emergency in which the Terminal Operations Personnel cannot prevent harm to personnel or equipment by taking reasonable and prudent actions such as valve manipulations, shutting down equipment, or initiating the Emergency Shutdown System. An Uncontrollable Emergency involves situations

that have the potential to result in exposure of personnel or property to natural gas in a liquid, cold vapor, or gaseous state or may result in fire or explosion. (Oregon LNG, Emergency Response Manual)

XI. CONCLUSIONS/RECOMMENDATIONS

Enormous U.S. deposits of natural gas buried in shale rock fields have flooded the domestic markets in the past few years. This gas surplus has changed the U.S. into an exporter of LNG versus an importer. The bottom has fallen out of the LNG import market. The single remaining importer is the Distrigas terminal in Boston Harbor in Everett, Massachusetts. It has one primary customer, the Mystic Power Station electric plant next door, under a long-term contract that does not expire until late next decade. (The Boston Globe, Jay Fitzgerald, January 23, 2013)

For the first time ever, the United States has the ability to become a major natural gas exporter, but that possibility comes with substantial economic and environmental risks. (LOOK BEFORE THE LNG LEAP, Craig Segall, Staff Attorney, Sierra Club Environmental Law Program)

XIII. FINDINGS: BIODIESEL

A. Transportation picture

The National Biodiesel Board lists 144 U.S. production plants in operation in for 2013. It must be noted that individuals unaware of federal and local regulations oftentimes try to blend their own biodiesel in their garages, shops or warehouses.

Biodiesel facilities in Washington State include the Gen-X Energy Group Inc., Moses Lake, which has a 6 million gallon per year nameplate capacity. General Biodiesel Seattle LLC has a 5 million gallon per year nameplate capacity. Imperium, Grays Harbor, located in Hoquiam, has a 100 million gallon per year nameplate capacity.

Biodiesel facilities in Oregon include Beaver Biodiesel LLC of Albany, which has a capacity of 0.94 million gallon per year nameplate capacity. SeSequential-Pacific Biodiesel, located in Salem, has a 17 million gallon per year nameplate capacity.

The Biodiesel facility in Idaho is Pleasant Valley Biofuels LLC, located in American Falls, and has a capacity of 5.5 million gallon per year nameplate capacity.

The Port of Tacoma has received proposals for a biodiesel/bulk liquids handling facility on the former Kaiser Aluminum smelter site on Blair Waterway. Port spokeswoman Tara Mattina said she could not discuss proposals because of ongoing negotiations.

Biodiesel infrastructure includes rail lines/railcars, barges/waterways, and tank trucks/highways. Pipelines are not often used. Infrastructure also includes terminals, storage tanks, blending facilities and transfer hubs.

Though no transportation routes were provided, an overview of biodiesel transport and marketing would look like this. Pure biodiesel product is transported to blending facilities by rail and truck, where it is mixed at the pipeline rack with petroleum diesel in the distribution terminal to provide B5-B20. These blends are transported to retailers by truck. The B100 product is also sold and used neat, as a more expensive “green” fuel.

B. Definition

Biodiesel is renewable diesel fuel substitute formulated exclusively for diesel engines. It is made from vegetable oil or animal fats derived from soybean, palm, algae, and/or recovered from commercial fryers then chemically processed with an alcohol such as methanol or ethanol. Methanol has been the most commonly used alcohol in the commercial production of biodiesel.

Biodiesel can be mixed with petroleum-based diesel fuel in any percentage, from 1 to 99, which is represented by a number following a B. For example, B5 is 5 percent biodiesel with 95 percent petroleum; B20 is 20 percent biodiesel with 80 percent petroleum, or B100 is 100 percent biodiesel, no petroleum.

Biodiesel is expected to play an increasingly important role in the world’s energy profile. Production has increased dramatically over the last several years, from an estimated 112 million gallons in 2005, to nearly 1.1 billion gallons in 2012 (National Biodiesel Board, 2013).

C. Characteristics

An oil-methanol blend produces a biodiesel with the following physical characteristics:

- Not very miscible with water
- Completely miscible with diesel
- Less dense than water
- More viscous than water or diesel
- Gels at high temperatures
- Very low vapor pressure (Low fire risk)
- Mildly corrosive to metals, plastics and other synthetic materials (potentially important from a spill response perspective)

In an extensive set of comparisons between petroleum diesels and several biodiesels produced from different feedstock oils, the following observations were noted:

- Biodiesels are much more naturally dispersible in water than petroleum diesels
- Biodiesels are in fact mild surfactants and form a milky white emulsion in water
- Biodiesel-diesel blends as low as B10 to B20 can disperse diesel into the water column.
- Biodiesel will physically auto-degrade (with light, high temperatures, oxidizers)
- Biodiesel (B100) will biodegrade in eight days or less under optimal nutrient and oxygen conditions, in activated sludge

- Under more typical conditions, biodiesel will biodegrade 80-90 percent in 28 days (versus 50 percent in 28 days for petroleum diesels)

D. Response strategies

A major producer of soy-based biodiesel in California (von Wedel, 1999) suggests that while biodiesel would be expected to manifest a lower toxicity and impact than petroleum diesel if spilled in the marine environment, the soy product is still toxic and noted that in an October 1997 ruling under the Clean Water Act, as amended by the Oil Pollution Act of 1990, vegetable oils are considered "oil"—like petroleum—in contrast to France, where biodiesel is classified as food for transportation purposes.

Von Wedel points out that spilling biodiesel into the water would be as illegal as discharging petroleum fuels overboard. Waterfowl and other birds, mammals and fish that get coated with vegetable oils could die from hypothermia or illness, or fall victim to predators. Even though the biodiesel is relatively non-toxic and less viscous than vegetable oil, it can still have a serious impact on marine and aquatic organisms in the event of a big spill.

Hollebone also tested skimmer recovery efficiencies with biodiesels relative to petroleum diesels and determined that biodiesels were slightly more amenable to skimming, with those biodiesels derived from vegetable stock most readily recovered. Hollebone attributed these differences to viscosity differences in the product. For sorbent materials, the behavior of biodiesels was very similar to standard fuels of similar viscosity. However, tests were not conducted near the gel points for biodiesels, and there were indications that emulsification of the oils might result in functional problems for the skimmers.

Some (e.g., Fernández-Álvarez, 2007) have suggested the potential use of biodiesel as a standalone cleanup agent unto itself, citing its oleophilic character, relative low cost, “non-toxicity,” and biodegradability. At least a few of Hollebone’s observations could be construed to support this application, although the fact that biodiesel tends to act as a built-in dispersant for the petroleum portion of a diesel blend would likely not be viewed as a positive characteristic for a remedial agent.

A 2007 Seattle-area spill at a biodiesel production facility provides insight into other potential response issues related to facilities accidents. The spill occurred July 27 at the Seattle Biodiesel plant located on the east shore of the Duwamish River in an industrialized area of the city. An employee was pumping a processing-chemical mixture of vegetable oil, biodiesel, sodium hydroxide, methanol and glycerin from a large tank to a small portable tank. The transfer was left unattended, however, and the small tank overflowed and the mixture ran across a driveway into a small inlet along the Duwamish River. Between 391 and 620 gallons of the mixture reached the waterway. All but 23 gallons were recovered. While this cleanup was relatively successful, response personnel anecdotally related that some component or components of the spilled mixture had a corrosive effect on certain parts of recovery

equipment such as skimmers. This could be attributable to the biodiesel itself (as noted by both Hollebhone and von Wedel) or possibly to some of the chemicals used in production (such as sodium hydroxide, sulfuric acid, or methanol). In the event of a spill of biodiesel or at a biodiesel production facility, it will be prudent to understand the basic aspects of manufacturing and the chemical structure of the fuel that may affect response equipment. In areas where biodiesel spills represent a modest risk, it may be prudent to retrofit gear with corrosion-resistant parts.

The chemistry of biodiesels may present other unanticipated challenges during a spill incident, attributable to their non-petroleum derivation and chemistry. For example, response chemists using a standardized approach to forensically “fingerprinting” oil residues for legal or other reasons may find their protocols to be inadequate for a fuel derived from biological feedstock. Spikmans et al. (2011) and Fuller et al. (2013) discuss the modified analytical and forensic approaches that are necessary to source identify biodiesels and characterize weathering in the products.

The information presently available for biodiesels generally suggests a lower occupational exposure risk to response and cleanup workers, with the important exception noted by Hollebhone that biodiesels may present an increased inhalation exposure risk. This should be considered during the determination of appropriate personal protection equipment, particularly during warmer conditions when increased volatility/evaporation could be expected in a spill.

The U.S. EPA has prepared and updated an overview of response for releases at biodiesel manufacturing facilities (Weston Solutions, 2008), focused on issues at production facilities. However, this guide contains excellent information and represents a good reference for spill response to biodiesel spills under any circumstances.

E. Safety issues

As a rule, biodiesels are less acutely toxic than their petroleum-based counterparts. Although oil in water dispersions of B5 and B20 blends were similarly toxic to rainbow trout as ultra low sulfur diesel, the neat (B100) biodiesels derived from canola, soy and tallow were much less so—or even nontoxic. With both Microtox® bacterial tests and the rainbow trout, the lowest toxicity results were obtained with the three B100 biodiesel formulations. Variably higher toxicity resulted from the blends and from petroleum diesel. Toxicity observations are as follows:

- Pure biodiesels are at least 5 times less acutely toxic than petroleum diesels
- Biodiesel blends up to B20 are similarly toxic to petroleum diesel
- The relationship between biodiesel content and toxicity is not linear
- No strong correlation between solubility and toxicity
- Large differences in organism sensitivity (with Microtox® > rainbow trout > water flea)
- Human lung cell assays: biodiesels more toxic than petroleum diesel; higher inhalation risk

- Biodiesels less toxic in rat tests than petroleum diesels, but wide variation among biodiesels

Ecological implications of biodiesel in the environment:

- Biodiesel biodegrades much more rapidly than conventional diesel
- Biodiesel in bulk can coat animals and inhibit oxygen transfer to aquatic species, similar to what would be expected for petroleum diesel
- Biodiesel is less toxic and has less of a solvent action than petroleum diesel
- Treatment of biodiesel-oiled wildlife would be similar to that for petroleum diesel exposures.
- Biodiesel has a high oxygen demand in water, which could result in fish kills.

Although biodiesel and biodiesel blends are less toxic than conventional diesel fuel, results from this study demonstrated that their risk to aquatic organisms is still quite substantial. Consequently, it will still have a serious impact on aquatic organisms if accidentally spilled or inadvertently discharged during transportation, storage, or use. Therefore, biodiesel and biodiesel blends should be handled with great care like any other fuel to avoid contamination to the watersheds, because their impact may have similar toxic effects as those of diesel spills

XIV. CONCLUSIONS / XV. RECOMMENDATIONS

Appropriate mitigation measures for release of biodiesel fuel include the following:

- A. Proper air monitoring equipment
 - Biodiesel fuel has a very low volatility at normal ambient temperatures and vapors are not typically an issue. However, vapors / mists may be generated when heated above 266 degrees Fahrenheit.
- B. Proper spill containment
 - Containment/response should follow typical oil containment procedures. Example: use oil-dry, petroleum-compatible absorbent socks, booms, etc.; the absorbent material used should be resistant to alcohol in the event methanol has further commingled with the biodiesel release. Disposal of biodiesel-contaminated soil or products can be considered non-hazardous provided methanol and/or hexane have not commingled with the release to meet the flammability characteristic for hazardous waste.
- C. Expected fate of biodiesel
 - Release in Soil
 - Biodegradation, with faster rates under aerobic conditions than anaerobic conditions, if it doesn't polymerize
 - Release in Water
 - Insoluble in water. Degradation varies in aquatic environments
 - Release in Air as result of spill/fire
 - Combustion produces carbon monoxide, carbon dioxide along with thick smoke
 - Release to storm/sanitary sewers

- May be high in free fatty acids and glycerol, and can have a high biochemical oxygen demand (BOD). These can disrupt wastewater treatment plant operations.

D. Overall health risks of biodiesel release

- Human Health Effects
 - Inhalation effects are negligible unless heated to produce vapors.
 - If biodiesel fuel were to be ingested, enzymes in the body called esterases would break the biodiesel fuel molecules into the component fatty acids and alcohol molecules. The alcohol is usually methanol and methanol is toxic. Thus, methanol toxicity could be a concern for ingestion of biodiesel fuel.
 - Neat biodiesel fuel is approximately 11 percent methanol by weight, so ingestion of 100 grams of biodiesel would release 11 grams, or 14 milliliters (mL) of methanol. For a 70-kilogram (kg) adult, the fatal dose of methanol ranges from 60 to 160 mL.
- Ecological Effects
 - Biodiesel may biodegrade more rapidly than conventional diesel. It depends.
 - When biodiesel is present in bulk in the environment, it can coat animals that come in contact with it and may reduce the ability of oxygen to reach aquatic systems. In this respect, its action is similar to petroleum diesel fuel.
 - The treatment of oiled birds and animals would be similar to the treatment provided when an oil spill occurs.
 - However, in water it has a high oxygen demand, which can lead to massive fish kills.

XVI. FINDINGS: SYNFUELS

A. Transportation picture

SYNFUELS transportation risks include; Vessel Collision, Sinking, Grounding, Fire, Allision, Breakaway, Rain/incidental water **and** Spillage of loose cargo.

B. Definition

Synthetic fuel or synfuel is generally a liquid fuel, less often a gaseous fuel, obtained from coal, natural gas, oil shale, biomass, or municipal waste. It may also refer to fuels derived from other solids such as plastics or waste rubber (such as used tires). The definition of synthetic fuel has been expanded from its traditional source materials of coal or natural gas to accommodate other naturally occurring or human-produced substances. In all cases, the end product is a combustible material intended for use in place of standard liquid petroleum fuels.

C. Characteristics

Both biofuels and synfuels have gained standing as alternatives to petroleum-based fuels in light of the inevitable scarcity of the latter as known reserves are tapped and drained. Although originally marketed as the means to grow or recycle our way to energy independence, biofuels and synfuels have more recently been shown to have

external costs that make them less than ideal as absolute replacements for petroleum; however, they can contribute, sometimes substantially, to the energy portfolio feeding the needs of an industrialized society.

Synfuels are not a new development; in fact, some of the advances in petroleum distillation that paved the way for the rise of oil as an energy source occurred because early industrial chemists were seeking ways to convert abundant coal resources into liquid fuels. Oil sands were excavated and processed by the French as early as 1735 (Speight, 2007). Production of fuels from biomass, such as agricultural by-products like cellulose or lignin, is currently less developed, but is the subject of considerable research.

The primary incentive for synfuel development and use is the imbalance between supply and demand for petroleum liquids and natural gas (Ghassemi and Iyer, 1981). While recent discoveries of new oil and gas reserves and the improved efficiencies of petroleum and natural gas extraction methods have decreased the immediate demand for synthetic fuels, growing consumption rates for transportation fuels in particular—projected to increase 100 percent by 2050 (Bulushev and Ross, 2011)—dictate that synthetic fuels will remain an important component of world energy production well into the future. As biomass-derived synfuels are considered to be “carbon neutral” because the carbon dioxide produced in their combustion is “recycled” from plant-based carbon and not extracted from the ground, there are increasing numbers of mandates (e.g., U.S. Department of Defense, European Union) for production and use of biomass-based synfuels.

D. Response strategies

Synthetic fuel manufacturers are producing synfuel because associated tax incentives have allowed them to provide bulk coal consumers with a cheaper energy source. These consumers consist of power plants, coke plants, steel manufacturers, etc. Some of the synfuels being produced consist of approximately 99% coal and 1% oil emulsion. These oil-coal synfuels have produced sheens in the marine environment when accidentally released. The sheen sighting in turn prompts a Coast Guard response with possible pollution fines and costly mitigation efforts. There are no current regulatory requirements for the marine transportation of synfuel. The need for a synfuel marine-transportation risk assessment arose due to a lack of guidance from the Federal Government regarding enforcement of the Clean Water Act/Federal Water Pollution Control Act with this product. Because of the lack of guidance, industry was reporting sheens resulting from the secondary effects of the residual synfuel binder, which creates a sheen when the non-regulated product (coal) is accidentally released into the marine environment. (SYNFUEL A Western Rivers Marine Transportation Risk Assessment)

E. Safety issues

Ghassemi and Iyer (1981) evaluated the known differences in chemical, combustion, and health effects characteristics of coal- and shale-derived synfuel products and their petroleum analogs. The coal and shale synfuels were notable in their higher

content of aromatic hydrocarbons and fuel-bound nitrogen and greater emissions of NO_x (nitrogen oxides) during combustion. Fuel oils from coal liquefaction processes and crude shale oil were identified as highly hazardous because of established mutagenic, tumorigenic, and cytotoxic properties. These characteristics were associated with high boiling and tarry coal and petroleum materials caused by the presence of polycyclic aromatic hydrocarbons, hetero- and carbonyl-polycyclic compounds, aromatic amines, and inorganics such as arsenic in shale oil. That these synfuels are considered to be comparatively more toxic than their petroleum equivalents should be factored into assessments of potential human and wildlife exposures in the event of synfuel spills.

Synthetic fuels from biomass-based sources are considered to have similar or less severe environmental effects than coal-based synfuels (Office of Technology Assessment, 1982). However, from a broader perspective, large-scale production of biomass-based synfuels may result in more severe ecosystem impacts due to the extensive and potentially intensive nature of the cultivation practices for the resource base, e.g., corn or rapeseed. However, these would be reduced with a greater reliance on what is currently considered to be agricultural waste as biomass feedstock.

Khan et al. (2007) directly compared the toxicity of petroleum diesel and biomass-derived diesel on water flea (*Daphnia magna*) and rainbow trout (*Onchorhynchus mykiss*) and found that biodiesel was considerably less acutely toxic than its petroleum analog. However, they cautioned:

Although biodiesel and biodiesel blends are less toxic than conventional diesel fuel, results from this study demonstrated that their risk to aquatic organisms is still quite substantial. Consequently, it will still have a serious impact on aquatic organisms if accidentally spilled or inadvertently discharged during transportation, storage, or use. Therefore, biodiesel and biodiesel blends should be handled with great care like any other fuel to avoid contamination to the watersheds, because their impact may have similar toxic effects as those of diesel spills.

XVII. CONCLUSIONS / XVIII. RECOMMENDATIONS

While the bulk of the “emerging risk” attention in the Northwest has been focused on the increased transport of oil sands products, coal, and Bakken crude oil through the region, the response community should at least remain aware that at some point in the future, synfuels may become a more significant part of the environmental risk equation. A challenge in generalizing a discussion of risk from synfuels is that the definition of the term has expanded to include source materials of widely differing origins and products with different chemical characteristics.

In every response, the basic question of “what is the material that spilled?” is key to every aspect of how the response is structured. Because synthetic fuels are fundamentally different from petroleum analogs, the need to distinguish a synthetic product and to understand its chemical structure is an important piece of the initial

response information. Knowing that a fuel is synthetic, and that it is derived from coal, shale, or biomass would be of great utility in predicting potential impact and in appropriately responding. It is beyond the scope of this limited review to detail regulatory requirements for labeling or documenting synthetic fuels, but it is worth noting that for spill response, more information is almost always better than less.

XIX. OVERALL EMERGING RISK PICTURE

The evaluation of risks associated with an increase in petroleum traffic, petroleum volume and emerging information on oil types conducted by the Emerging Risks Task Force identified that, overall, the risks are a function of the shifting transportation of petroleum products by rail to inland areas and an associated predicted decrease in marine transportation of petroleum within the NW Area. Conversely, this is complicated by other potential changes which could increase the number of cargo ships calling on ports in the Northwest, the number of tank ships carrying crude oil out from Canadian ports through U.S. waters, and the number of tank ships (most likely barges) moving various types of crude oil via rail terminals to refineries in Washington or California.

In October 2012, the Washington Puget Sound Partnership Oil Spill Work Group and [Puget Sound Harbor Safety Committee](#) formed a joint Vessel Traffic Risk Assessment Steering Committee, comprising about a dozen representatives drawn from several maritime industry sectors, the Makah Nation, Washington Association of Counties, the Department of Ecology and the U.S. Coast Guard. The purpose of this study was to assess the relative risk in Puget Sound for vessels as the oil-movement picture changes. The information from the study will be used to evaluate potential risk mitigation measures. Our Task Force suggests that the Area Committee monitor the progress of the study and use the information to update this report and help implement mitigating measures that emerge, as appropriate. In addition, various Washington State proposed crude-by-rail projects discussed in this report may have permit requirements for more localized risk studies to help determine the risk impacts of the projects. These studies should be monitored as well.

New Petroleum Products and Risks, or More of the Same?

While there is a perception that the petroleum products in question - and particularly Canadian Oil Sands Products (OSP) and Bakken crude oil - represent materials that are “new” to the response community in the NW Area, this turns out to be false. OSP have been transported to the four northern Puget Sound refineries through the Trans Mountain Pipeline system since 1980 with no spills or operational issues (per The Center for Spills in the Environment, 2013). Under the U.S. Coast Guard’s definition of oils as set forth in Title 33 Code of Federal Regulations, Volume 2, Part 155, the OSP of concern - dilbit crude, synbit crude and syndilbit crude - fall within the parameters of Group IV oils, similar in physical and chemical characteristics to many other heavy crude oils delivered to area refineries by tank vessel since the 1950s. While Bakken crude oil is a new crude oil on the world market and a new feed stock to area

refineries, Bakken crude exhibits physical and chemical properties which classify it as a Group II oil under the USCG definition, making it analogous from a response standpoint to many other Light Crude Oils, Diesel Fuel, Jet Fuel and Kerosene. Similar light crude oils have been utilized by area refineries throughout their histories as driven by product specification requirements and crude market prices. Moreover, Jet Fuel and Diesel Fuel are transported regionally by pipeline and in tank trucks daily. Both Group II and Group IV oils are very familiar to Oil Spill Removal Organizations (OSROs) and to Incident Management Teams (IMTs) in the NW Area and much of the region's response equipment is designed specifically to address spills of both of these classes of oils.

Category	API Gravity	Examples
Group 1	>45	Gasoline, Condensate
Group 2	35 – 45	Kerosene, Jet Fuel, Diesel, No. 2 Fuel Oil
Group 3	17.5 – 35	Medium Crudes, IFO
Group 4	10 - 17.5	Heavy Crudes, Bunkers, No 6 Fuel Oil
Group 5	<10	Residual Oils, Asphalt

In their report on the 2013 Alberta Oil Sands Workshop, the Center for Spills in the Environment noted, “There are many open questions that need to be answered in order to better predict or model how heavy oils or OSP react after a spill” (p. 12). The general lack of precision regarding the prediction or modeling of the fate and effects of all heavy oils once released into marine waters - including OSP - remains a risk. As to OSP, more work is needed to understand the variety of diluents that may vary the characteristics of the products delivered to Washington refineries. Ongoing effort to improve the ability to better predict the behavior of these products, and thus direct a broad range of response operations, is warranted.

One of the recommendations from the 2013 Alberta Oil Sands Workshop was to ensure that Northwest area responders have plans in place and are equipped with appropriate equipment to monitor the safety of communities

and responders, in particular to monitor benzene levels associated with spills of Bakken oil.

Rerouting the Risk

While the “new” petroleum products being introduced to the NW Area themselves may not constitute a new risk, what is different are the routes by which these petroleum products are and will be transported and the volumes being transported via these routes. Proposed routes and modes of transportation of petroleum products moving through Idaho, Oregon and Washington are addressed in Section I. of this document. The refining capacity is fixed. The transborder pipeline capacity is not maximized and is expected to increase in the foreseeable future. With anticipated increases in delivery of petroleum products by rail and pipeline, the NW Area can expect to experience a decrease in delivery of crude oil by tank vessel and an associated decrease in regional marine crude oil spill risk.

Risk assessments of the transportation of petroleum products have repeatedly shown that changes in transportation systems often shift risk from one location to another rather than reduce overall system risk. This tenet may hold true for the transportation of OSP and Bakken crude, particularly as it pertains to the transportation of these products by rail and the distribution of response resources - both equipment and personnel - relative to these inland transportation corridors.

In its most simple terms, risk is the product of consequence and probability, represented by the following equation:

$$R = L \times p \quad (1)$$

Where: R = Risk

L = Loss or consequence, and

p = probability of occurrence

It can also be described in terms of frequency and severity. If we look at risk of an oil spill associated with increased petroleum transportation by rail, we find that the larger number of trains transporting oil, the higher the probability that one of these trains will experience an incident resulting in a loss of containment. Consequence or loss associated with any single incident has not necessarily increased, as the size of the trains transporting petroleum products has not changed appreciably from the Unit Train of ± 100 rail cars; however, BNSF Railways has reported a 300 percent increase in crude transport in 2011-2012 over previous years with the overwhelming majority of that volume being Bakken crude deliveries to Washington and Oregon. This significant increase in the number of trains transporting petroleum products translates into increased probability of occurrence and, therefore,

increased incremental risk of a rail transportation-related spill along these inland rail corridors.

Additionally, this represents a change in severity, as we now must plan for spills of persistent oils in inland areas where previously the inland scenario was an oil type with a non-persistent characteristic.

Changes to the NWACP

The characteristics of OSP and Bakken crude fall within parameters that are currently addressed within the Northwest Area Contingency Plan (NWACP), though additional studies are needed to better understand the spill behavior/fate/effects/toxicity/ dispersant efficacy information. The focus on OSP has increased recognition that current fate and effects predictive modeling does not adequately address all aspects of the heavier Group IV oils and more work in this area is warranted.

Where the NWACP has traditionally focused on response to spills of oil to marine waters, recent changes and future trends in modes of crude oil transportation in the NW Area reflect a geographic shift to inland areas with a focus on rail transportation. This will result in a change in response strategy and response resource utilization and may warrant a review of the distribution of response resources. Federal On-Scene Coordinators will need to re-focus Preparedness and Response resources from traditional marine-based scenarios to a broader range of scenarios and work with Plan-holders to ensure that transfer of custody issues - and associated response expectations - are clearly articulated within Contingency Plans.

References:

The Center for Spills in the Environment, University of New Hampshire. 2013.

Alberta Oil Sands Workshop for Washington Department of Ecology, the Regional Response Team 10 and the Pacific States/British Columbia Oil Spill Task Force.

Recommendation Matrix

Recommendation	Owner	Tracking
III. Continue to support and monitor the outcome of the current risk studies, in particular the Vessel Traffic Risk Assessment, which could lead to a series of recommendations to manage the changing risks in the Northwest.	Area Planning Committee, Scott Knutson	Aug 2013: The VTRA Steering Committee expects a final report to be completed in Oct 2013.
III. Monitor studies that are occurring in Canada to support the various proposed projects to improve our understanding of the fate & effects, efficacy of dispersants and long-term toxicity of OSP.		
III. Study the distribution of response equipment between inland and marine areas to assess whether we are prepared for the changing inland risks.		
VI. Monitor the VTRA.		See Recommendation III
IX. Assess the risk of spills of nonfloating oils to determine the resources at risk.		
IX. Develop response plans that include consultation and coordination protocols and obtain pre-approvals and authorizations to facilitate responses to such spills.		
IX. Educate stakeholder groups about the impact and methods for tracking, containing, and recovering oil suspended in the water column or on the seabed.		
IX. Include at least one scenario for responding to a nonfloating oil spill in training or drill programs.		
IX. Establish scientific support teams to respond to nonfloating-oil spills.		
IX. Disseminate and share knowledge learned from nonfloating oil spills as part of ongoing training programs.		
IX. Develop an evaluation program for tracking oil in the water column and on the seabed, as well as		

<p>containment and recovery techniques for use on the seabed. Document findings and distribute to the environmental response community to improve response plans for spills of nonfloating oils.</p>		
<p>IX. Require tests of area contingency plans and industry response plans for responses to spills of nonfloating oils as part of training and drill programs.</p>		
<p>IX. Conduct Government-Initiated Unannounced Exercises for companies that transport sinking oils over the waters in D13 / Region 10, with the specific objective of determining if they are prepared with the tools, strategies and tactics to carry out their companies' response plan with respect to sinking oils.</p>		
<p>XIV. Ensure proper air-monitoring equipment for biodiesel fuel response.</p>		
<p>XIV. Ensure proper spill containment for biodiesel fuel response. Containment/response should follow typical oil containment procedures.</p>		
<p>XVII. Remain aware that at some point in the future, synfuels may become a more significant part of the environmental risk equation.</p>		

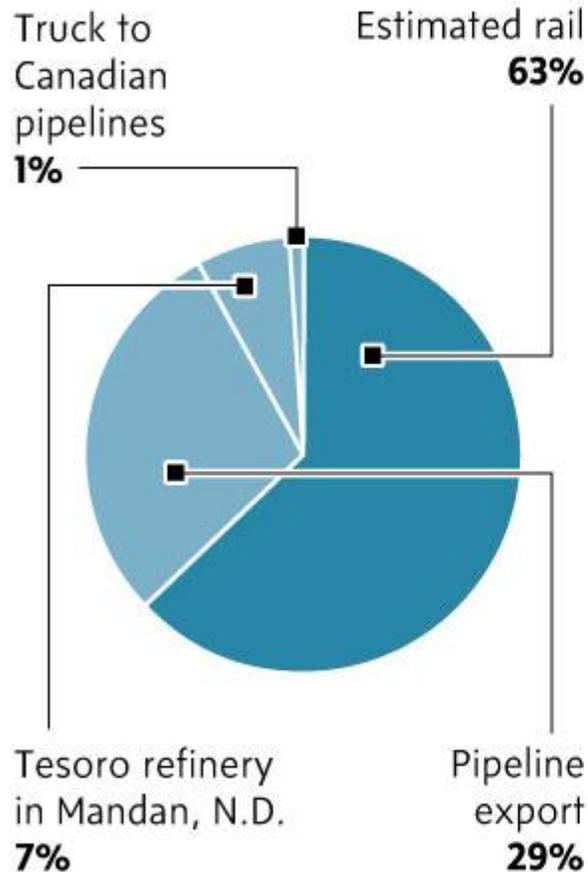
How oil is transported from North Dakota's Williston Basin

The Globe and Mail

Published Monday, Dec. 02 2013, 6:00 AM EST

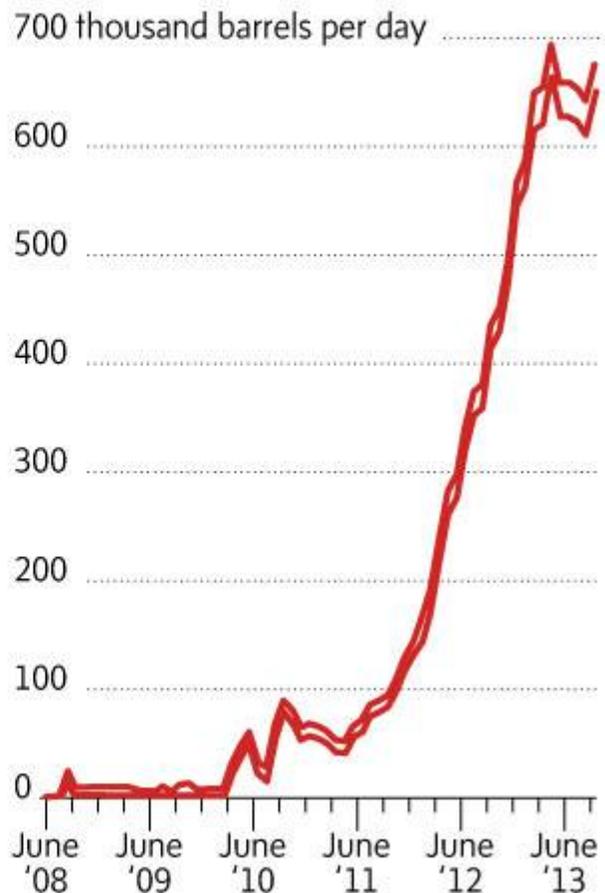
Last updated Monday, Dec. 02 2013, 12:15 AM EST

Williston Basin oil output



SOURCE: NORTH DAKOTA PIPELINE AUTHORITY

North Dakota oil export volumes by rail



More Related to this Story

- [GLOBE INVESTIGATION Inside the oil-shipping free-for-all that brought disaster to Lac-Mégantic](#)

- [Last moments of Lac-Mégantic: Survivors share their stories](#)
- [Lac-Mégantic disaster](#)

Combined North American rail volume for the 34 weeks of 2013 on 13 reporting U.S., Canadian and Mexican railroads totaled 12,645,588 carloads, down 0.3 percent compared with the same point last year, and 10,390,003 trailers and containers, up 3.5 percent compared with last year.

 WEEKLY RAIL TRAFFIC CHARTS (PDF)

###

For more information contact: Abigail Gardner, AARMedia@skdknick.com, 202-464-6603, or Holly Arthur, harthur@aar.org, 202-639-2344.

About AAR: The Association of American Railroads (AAR) is the world's leading railroad policy, research and technology organization focusing on the safety and productivity of rail carriers. AAR members include the major freight railroads of the U.S., Canada and Mexico, as well as Amtrak. Learn more at www.aar.org. Follow us on Twitter: [AAR FreightRail](https://twitter.com/AAR_FreightRail) or Facebook: www.facebook.com/freightrail.



U.S. Rail Traffic¹

Week 34, 2013 – Ended August 24, 2013

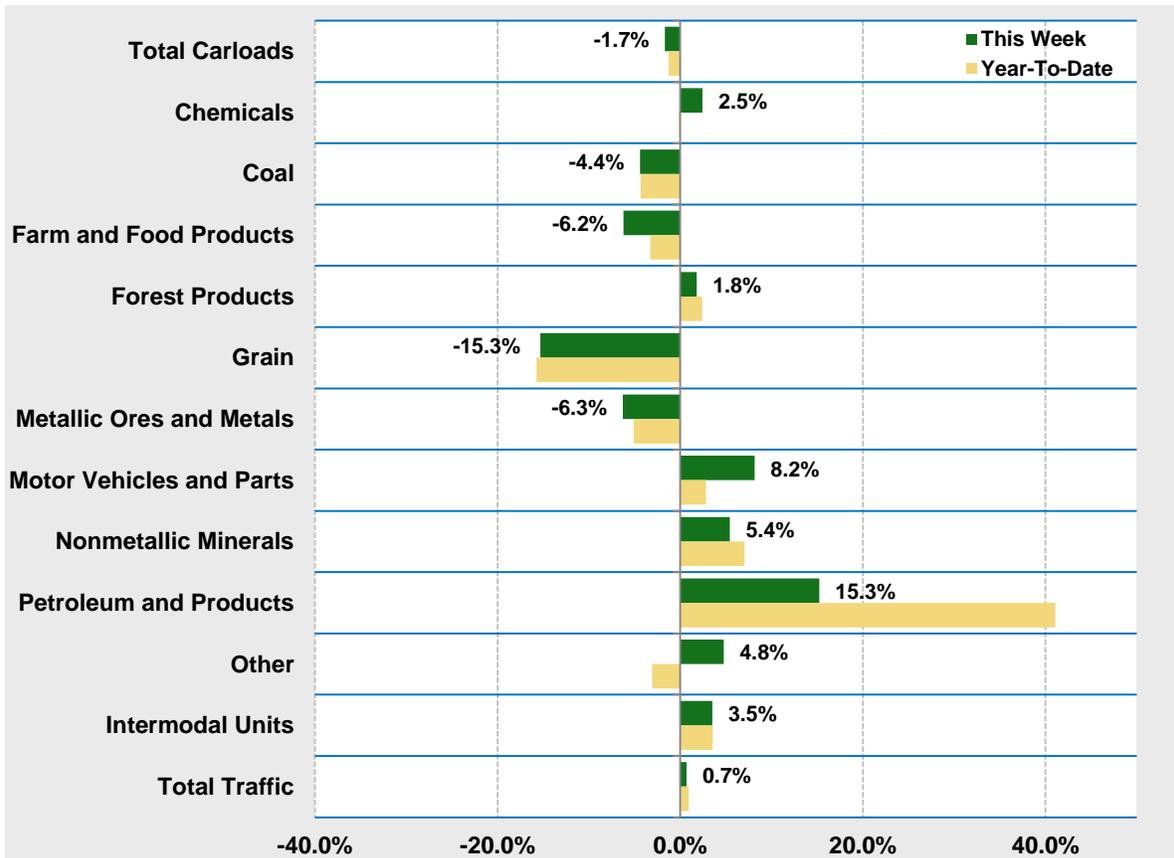
	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ²	vs 2012
Total Carloads	291,889	-1.7%	9,478,728	278,786	-1.2%
Chemicals	30,052	2.5%	1,012,447	29,778	-0.1%
Coal	119,779	-4.4%	3,772,035	110,942	-4.3%
Farm and Food Products, Excluding Grain	15,579	-6.2%	552,723	16,257	-3.3%
Forest Products	11,066	1.8%	372,448	10,954	2.4%
Grain	15,925	-15.3%	567,218	16,683	-15.7%
Metallic Ores and Metals	24,898	-6.3%	835,992	24,588	-5.1%
Motor Vehicles and Parts	16,898	8.2%	540,100	15,885	2.8%
Nonmetallic Minerals and Products	36,459	5.4%	1,110,345	32,657	7.0%
Petroleum and Petroleum Products	12,764	15.3%	460,082	13,532	41.1%
Other	8,469	4.8%	255,338	7,510	-3.1%
Intermodal Units	257,080	3.5%	8,260,570	242,958	3.5%
Total Traffic	548,969	0.7%	17,739,298	521,744	0.9%

¹ Excludes U.S. operations of CN and Canadian Pacific.

² Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

United States



Canadian Rail Traffic¹

Week 34, 2013 – Ended August 24, 2013

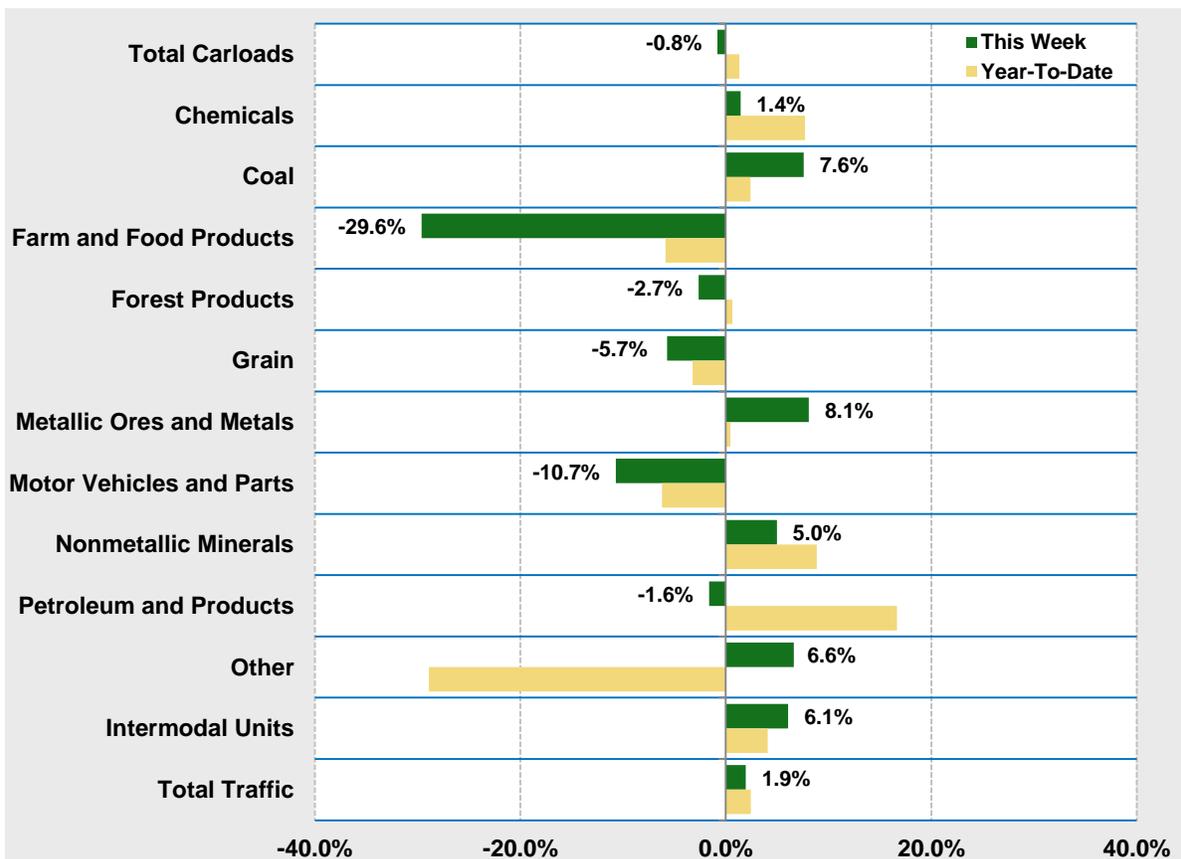
	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ²	vs 2012
Total Carloads	79,241	-0.8%	2,640,013	77,647	1.3%
Chemicals	10,498	1.4%	385,595	11,341	7.7%
Coal	9,751	7.6%	307,281	9,038	2.4%
Farm and Food Products, Excluding Grain	4,400	-29.6%	197,817	5,818	-5.9%
Forest Products	7,959	-2.7%	263,195	7,741	0.6%
Grain	8,227	-5.7%	281,598	8,282	-3.2%
Metallic Ores and Metals	18,486	8.1%	558,094	16,415	0.4%
Motor Vehicles and Parts	5,179	-10.7%	179,173	5,270	-6.2%
Nonmetallic Minerals and Products	6,507	5.0%	197,661	5,814	8.9%
Petroleum and Petroleum Products	6,300	-1.6%	223,098	6,562	16.7%
Other	1,934	6.6%	46,501	1,368	-28.9%
Intermodal Units	56,458	6.1%	1,803,603	53,047	4.1%
Total Traffic	135,699	1.9%	4,443,616	130,695	2.4%

¹ Includes U.S. operations of CN and Canadian Pacific.

² Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

Canada



Mexican Rail Traffic

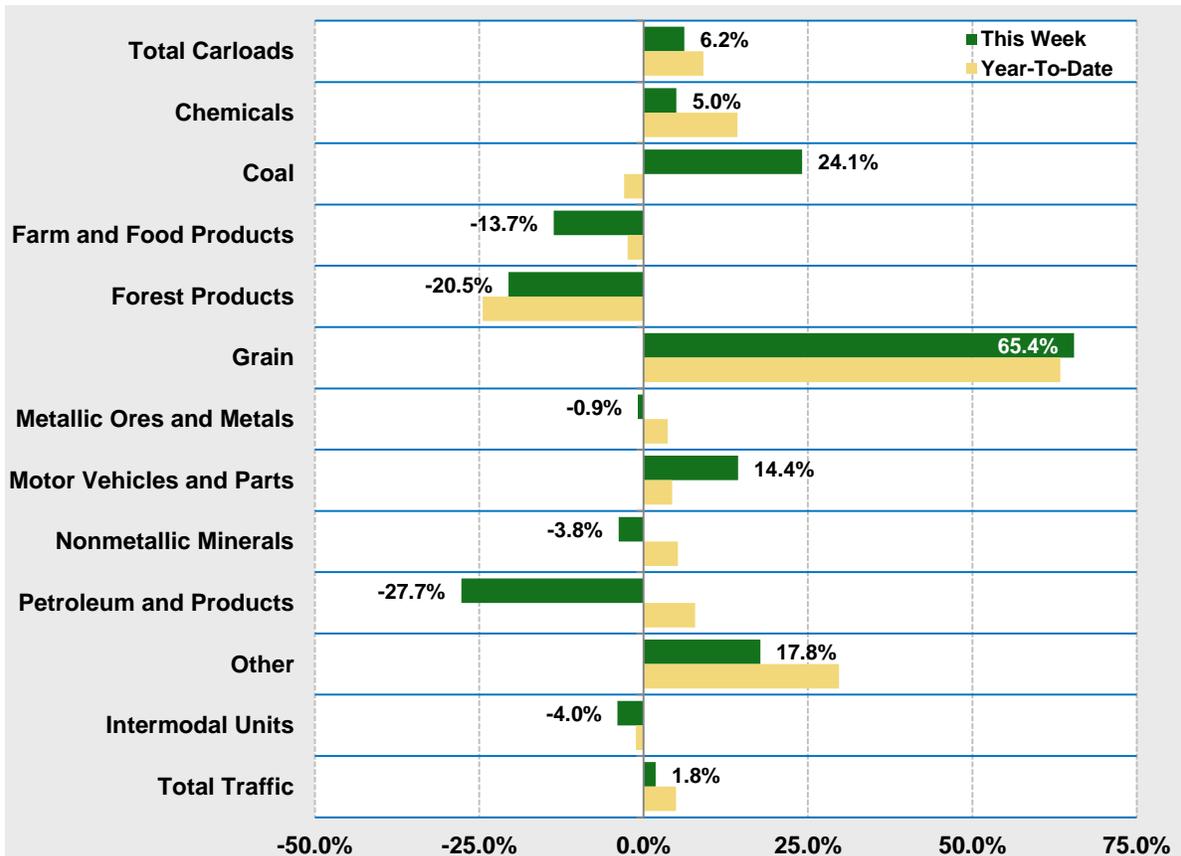
Week 34, 2013 – Ended August 24, 2013

	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ¹	vs 2012
Total Carloads	15,857	6.2%	526,847	15,496	9.1%
Chemicals	1,219	5.0%	47,860	1,408	14.3%
Coal	242	24.1%	4,860	143	-3.0%
Farm and Food Products, Excluding Grain	1,430	-13.7%	50,357	1,481	-2.5%
Forest Products	58	-20.5%	1,639	48	-24.5%
Grain	1,853	65.4%	53,202	1,565	63.4%
Metallic Ores and Metals	4,011	-0.9%	137,941	4,057	3.7%
Motor Vehicles and Parts	4,086	14.4%	120,032	3,530	4.3%
Nonmetallic Minerals and Products	2,046	-3.8%	76,064	2,237	5.2%
Petroleum and Petroleum Products	388	-27.7%	14,843	437	7.8%
Other	524	17.8%	20,049	590	29.7%
Intermodal Units	10,691	-4.0%	325,830	9,583	-1.2%
Total Traffic	26,548	1.8%	852,677	25,079	4.9%

¹ Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

Mexico



North American Rail Traffic

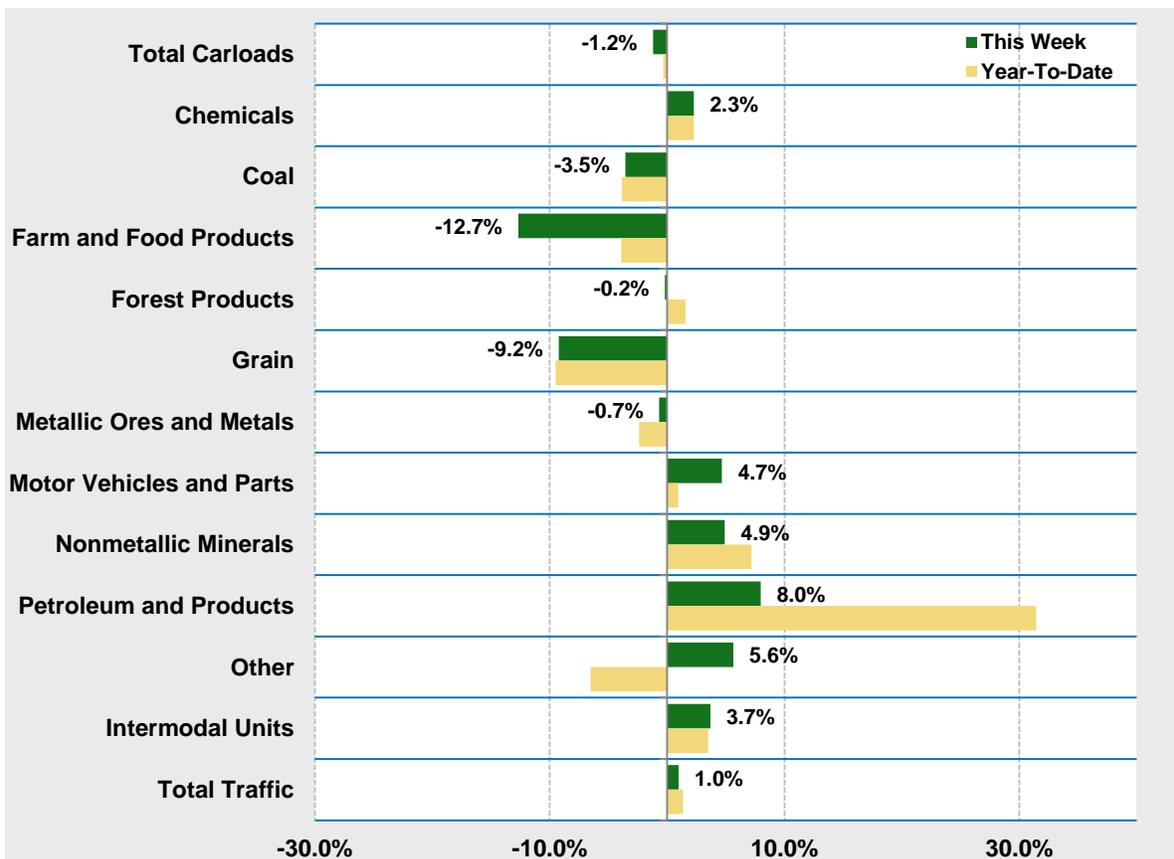
Week 34, 2013 – Ended August 24, 2013

	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ¹	vs 2012
Total Carloads	386,987	-1.2%	12,645,588	371,929	-0.3%
Chemicals	41,769	2.3%	1,445,902	42,527	2.3%
Coal	129,772	-3.5%	4,084,176	120,123	-3.9%
Farm and Food Products, Excluding Grain	21,409	-12.7%	800,897	23,556	-3.9%
Forest Products	19,083	-0.2%	637,282	18,744	1.6%
Grain	26,005	-9.2%	902,018	26,530	-9.5%
Metallic Ores and Metals	47,395	-0.7%	1,532,027	45,060	-2.4%
Motor Vehicles and Parts	26,163	4.7%	839,305	24,685	1.0%
Nonmetallic Minerals and Products	45,012	4.9%	1,384,070	40,708	7.2%
Petroleum and Petroleum Products	19,452	8.0%	698,023	20,530	31.4%
Other	10,927	5.6%	321,888	9,467	-6.5%
Intermodal Units	324,229	3.7%	10,390,003	305,588	3.5%
Total Traffic	711,216	1.0%	23,035,591	677,517	1.4%

¹ Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

North America



Major Rail Traffic Groups And the Associated *Weekly Railroad Traffic* Commodity Categories

Chemicals
Chemicals
Coal
Coal
Farm and Food Products, Excl. Grain
Farm Products, Excluding Grain
Grain Mill Products
Food & Kindred Products
Forest Products
Primary Forest Products
Lumber & Wood Products
Pulp, Paper & Allied Products
Grain
Grain
Metallic Ores and Metals
Metallic Ores
Coke
Metals & Products
Iron & Steel Scrap
Motor Vehicles and Parts
Motor Vehicles & Parts
Nonmetallic Minerals and Products
Crushed Stone, Sand & Gravel
Nonmetallic Minerals
Stone, Clay & Glass Products
Petroleum and Petroleum Products
Petroleum Products
Other
Waste & Nonferrous Scrap
All Other Carloads
Intermodal
Containers
Trailers

Weekly traffic data for the detailed commodity groups are available in the AAR's *Weekly Railroad Traffic* report, which can be ordered at <https://www.aar.org/Pages/ProductDetails.aspx?ProductCode=WRT2013>. Monthly traffic data for the detailed commodity groups are available in our *Rail Time Indicators* report, which costs \$50 for 12 monthly issues. RTI can also be purchased with a spreadsheet containing monthly traffic data by country and commodity for \$100. *Rail Time Indicators* may be ordered at www.aar.org/Pages/AllProducts.aspx.



ABOUT AAR

JOIN AAR

FREIGHT RAI

Weekly Rail Traffic Summary ▶ AAR Reports October And Weekly Rail Traffic Gains, 3Q Crude Oil Up Year Over Year

11/7/2013

FOR IMMEDIATE RELEASE

AAR Reports October and Weekly Rail Traffic Gains, 3Q Crude Oil Up Year Over Year

WASHINGTON, D.C. – Nov. 7, 2013 – The Association of American Railroads (AAR) today reported increased U.S. rail traffic for October 2013. Intermodal traffic in October totaled 1,317,601 containers and trailers, up 6.8 percent (84,120 units) compared with October 2012. The weekly average of 263,520 intermodal units in October 2013 was the highest weekly average for any month in history. Carloads originated in October totaled 1,443,609, up 1.5 percent or 21,059 carloads compared with the same month last year. This represents the highest year-over-year percentage total carload increase in the last 22 months, although rail traffic in late October 2012 was impacted by Hurricane Sandy.

Fifteen of the 20 commodity categories tracked by the AAR each month saw year-over-year carload increases in October 2013 compared with October 2012. Commodities with the largest monthly carload increases included grain, up 9,450 carloads or 9.3 percent; petroleum and petroleum products, up 8,426 carloads or 14.2 percent, and crushed stone, gravel, and sand, up 7,664 carloads or 7.2 percent. Commodity categories with carload declines last month included coal, down 30,428 carloads or 5.4 percent compared with October 2012, and farm products excluding grain, down 3,738 carloads, or 46.2 percent.

Excluding coal and grain, U.S. carloads in October 2013 were up 5.6 percent, or 42,037 carloads. “There’s been some concern lately that the recovery may be running out of steam. Rail traffic data for October doesn’t seem to support that,” said AAR Senior Vice President John T. Gray. “A number of economically sensitive commodities, like lumber, autos, and chemicals, saw higher traffic volumes in October. The sharp increase in grain carloadings is a welcome change and points to the cooperative relationship railroads have established with their partners in the agricultural community.”

AAR today also reported that U.S. Class I railroads originated 93,312 carloads of crude oil in the third quarter of 2013 (3Q), up 44.3 percent over the 64,658 carloads originated in 3Q 2012, but down 14.1 percent from the 108,605 carloads originated in the second quarter of 2013.

AAR today also reported increased rail traffic for the week ending Nov. 2, 2013. U.S. railroads originated 292,398 carloads last week, up 5.1 percent compared with the same week last year, while intermodal volume for the week totaled 264,264 units, up 17.7 percent compared with the same week last year. Total U.S. rail traffic last week was 556,662 carloads and intermodal units, up 10.8 percent compared with the same week last year. Rail traffic in the comparable week of 2012 was affected by Hurricane Sandy.

Eight of the 10 carload commodity groups tracked on a weekly basis posted increases compared with the same week in 2012, including nonmetallic minerals and products, up 18.6 percent; motor vehicles and parts, up 15.9 percent; and petroleum and petroleum products, up 12.6 percent. The groups showing a decrease in weekly traffic compared with the same week last year included farm and food products, excluding grain, down 3.3 percent; and coal, down 1.2 percent.

For the first 44 weeks of 2013, U.S. railroads reported cumulative volume of 12,384,147 carloads, down 0.7 percent from the same point last year, and 10,865,365 intermodal units, up 4.0 percent from last year. Total U.S. traffic for the first 44 weeks of 2013 was 23,249,512 carloads and intermodal units, up 1.5 percent from last year.

Canadian railroads reported 83,000 carloads for the week, up 6.8 percent compared with the same week last year, and 54,867 intermodal units, up 8.3 percent compared with the same week in 2012. For the first 44 weeks of 2013, Canadian railroads reported cumulative volume of 3,471,365 carloads, up 2.1 percent, and 2,370,520 intermodal units, up 4.2 percent from the same period last year.

Mexican railroads reported 14,281 carloads for the week, down 0.4 percent compared with the same week last year, and 8,928 intermodal units, down 15.0 percent. Cumulative volume on Mexican railroads for the first 44

weeks of 2013 is 669,971 carloads, up 6.8 percent from the same point last year, and 444,314 intermodal units, up 0.5 percent.

Combined North American rail volume for the first 44 weeks of 2013 on 13 reporting U.S., Canadian and Mexican railroads totaled 16,525,483 carloads, up 0.2 percent compared with the same point last year, and 13,680,199 trailers and containers, up 3.9 percent compared with last year.

 [WEEKLY RAIL TRAFFIC CHARTS \(PDF\)](#)

###

For more information contact: Abigail Gardner, 202-464-6603, at AARMedia@skdknick.com, or Holly Arthur, harthur@aar.org, 202-639-2344.

About AAR: The Association of American Railroads (AAR) is the world's leading railroad policy, research and technology organization focusing on the safety and productivity of rail carriers. AAR members include the major freight railroads of the U.S., Canada and Mexico, as well as Amtrak. Learn more at www.aar.org. Follow us on Twitter: AAR_FreightRail or Facebook: www.facebook.com/freightrail.



U.S. Rail Traffic¹

Week 44, 2013 – Ended November 2, 2013

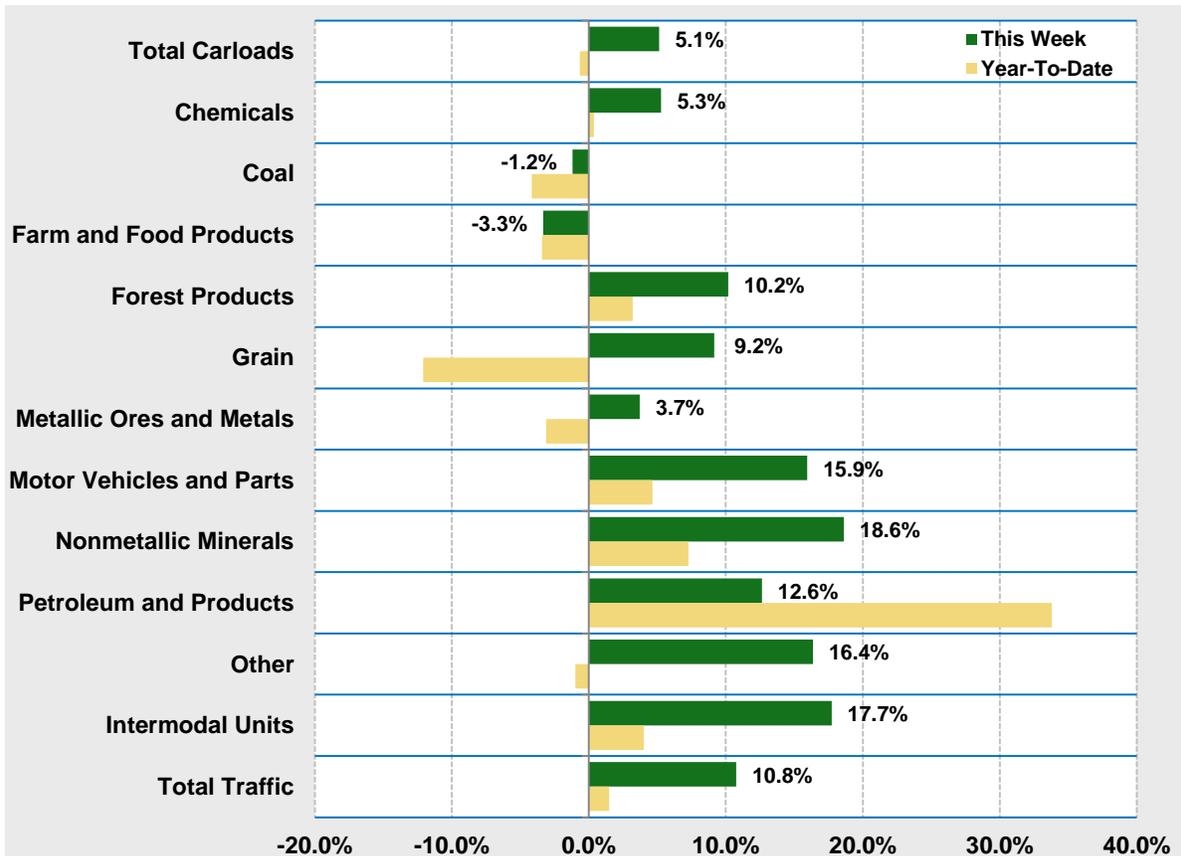
	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ²	vs 2012
Total Carloads	292,398	5.1%	12,384,147	281,458	-0.7%
Chemicals	30,095	5.3%	1,310,775	29,790	0.4%
Coal	111,064	-1.2%	4,898,065	111,320	-4.2%
Farm and Food Products, Excluding Grain	17,945	-3.3%	719,282	16,347	-3.4%
Forest Products	11,355	10.2%	483,336	10,985	3.2%
Grain	20,833	9.2%	763,891	17,361	-12.1%
Metallic Ores and Metals	23,432	3.7%	1,092,837	24,837	-3.1%
Motor Vehicles and Parts	18,419	15.9%	716,243	16,278	4.6%
Nonmetallic Minerals and Products	37,626	18.6%	1,472,426	33,464	7.3%
Petroleum and Petroleum Products	13,607	12.6%	592,492	13,466	33.8%
Other	8,022	16.4%	334,800	7,609	-1.0%
Intermodal Units	264,264	17.7%	10,865,365	246,940	4.0%
Total Traffic	556,662	10.8%	23,249,512	528,398	1.5%

¹ Excludes U.S. operations of CN and Canadian Pacific.

² Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

United States



Canadian Rail Traffic¹

Week 44, 2013 – Ended November 2, 2013

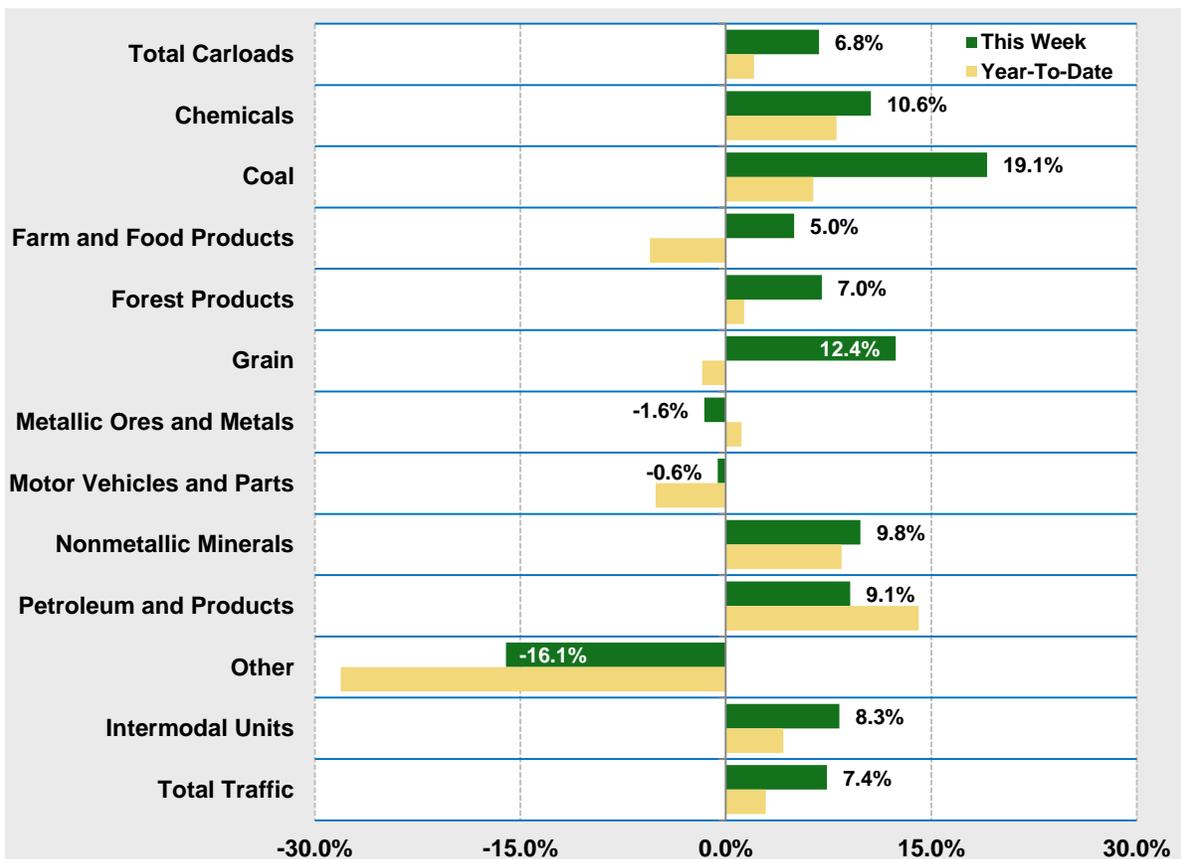
	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ²	vs 2012
Total Carloads	83,000	6.8%	3,471,365	78,895	2.1%
Chemicals	10,884	10.6%	497,376	11,304	8.1%
Coal	9,876	19.1%	406,703	9,243	6.4%
Farm and Food Products, Excluding Grain	7,144	5.0%	273,284	6,211	-5.5%
Forest Products	7,965	7.0%	340,814	7,746	1.3%
Grain	11,826	12.4%	381,700	8,675	-1.7%
Metallic Ores and Metals	15,771	-1.6%	724,896	16,475	1.2%
Motor Vehicles and Parts	5,507	-0.6%	235,089	5,343	-5.1%
Nonmetallic Minerals and Products	5,552	9.8%	260,078	5,911	8.5%
Petroleum and Petroleum Products	6,907	9.1%	288,549	6,558	14.1%
Other	1,568	-16.1%	62,876	1,429	-28.1%
Intermodal Units	54,867	8.3%	2,370,520	53,875	4.2%
Total Traffic	137,867	7.4%	5,841,885	132,770	2.9%

¹ Includes U.S. operations of CN and Canadian Pacific.

² Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

Canada



Mexican Rail Traffic

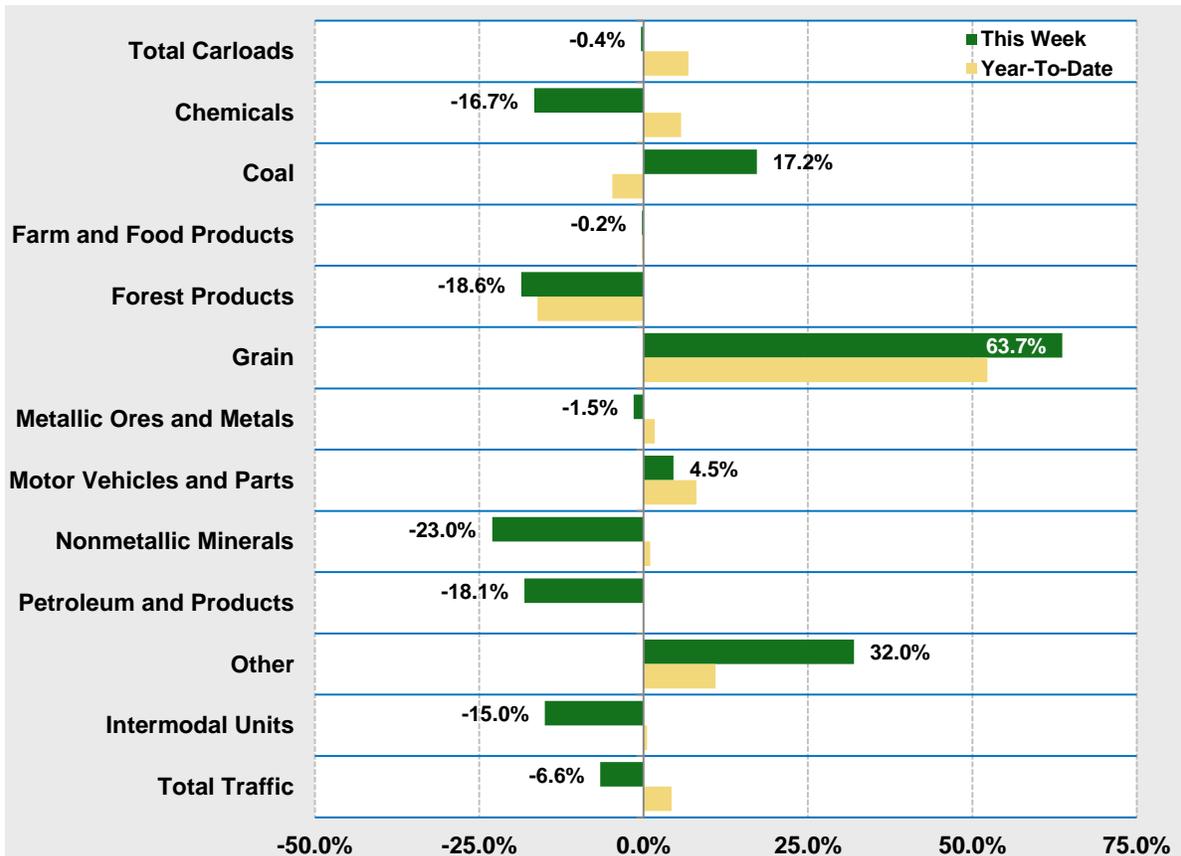
Week 44, 2013 – Ended November 2, 2013

	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ¹	vs 2012
Total Carloads	14,281	-0.4%	669,971	15,227	6.8%
Chemicals	1,071	-16.7%	58,889	1,338	5.7%
Coal	177	17.2%	6,495	148	-4.8%
Farm and Food Products, Excluding Grain	1,234	-0.2%	64,371	1,463	-0.3%
Forest Products	35	-18.6%	2,237	51	-16.2%
Grain	1,162	63.7%	65,431	1,487	52.3%
Metallic Ores and Metals	3,704	-1.5%	174,213	3,959	1.7%
Motor Vehicles and Parts	4,094	4.5%	162,630	3,696	8.0%
Nonmetallic Minerals and Products	1,723	-23.0%	94,930	2,158	1.0%
Petroleum and Petroleum Products	388	-18.1%	18,363	417	0.1%
Other	693	32.0%	22,412	509	10.9%
Intermodal Units	8,928	-15.0%	444,314	10,098	0.5%
Total Traffic	23,209	-6.6%	1,114,285	25,325	4.2%

¹ Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

Mexico



North American Rail Traffic

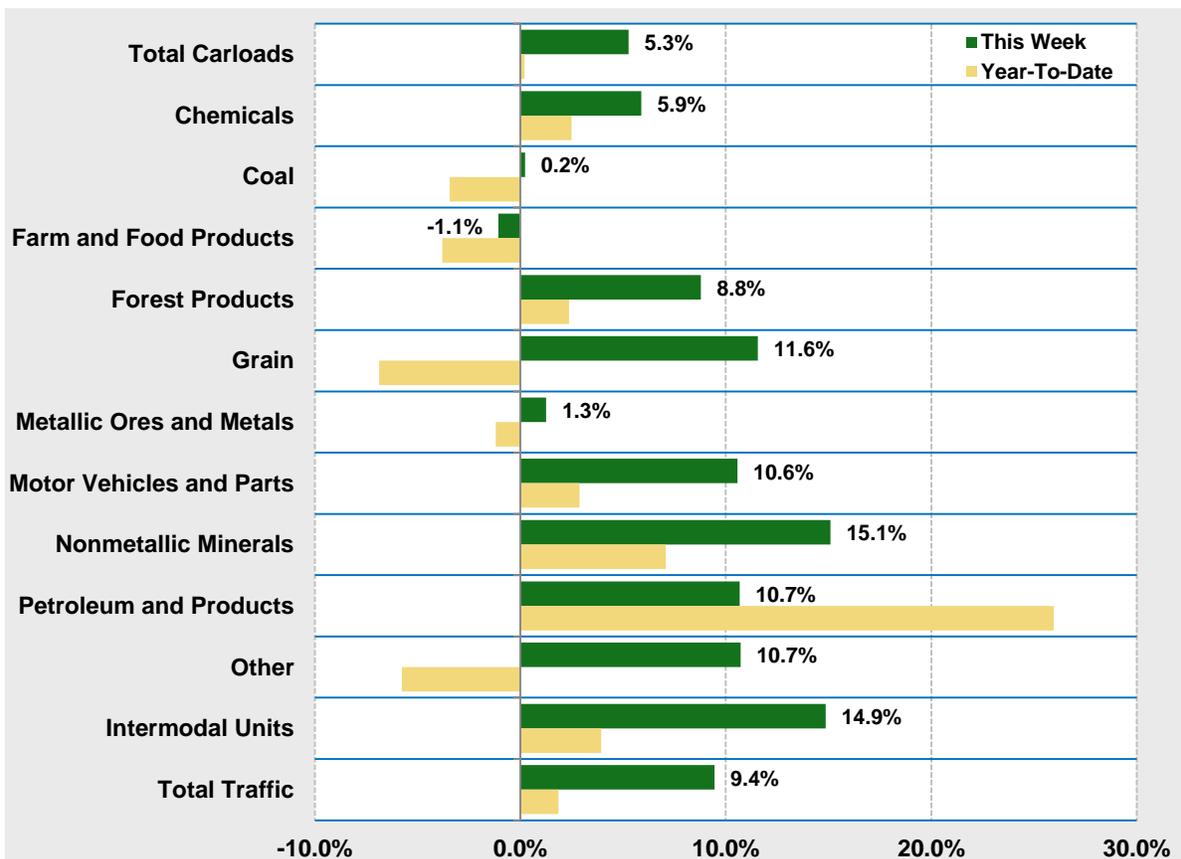
Week 44, 2013 – Ended November 2, 2013

	This Week		Year-To-Date		
	Cars	vs 2012	Cumulative	Avg/wk ¹	vs 2012
Total Carloads	389,679	5.3%	16,525,483	375,579	0.2%
Chemicals	42,050	5.9%	1,867,040	42,433	2.5%
Coal	121,117	0.2%	5,311,263	120,711	-3.4%
Farm and Food Products, Excluding Grain	26,323	-1.1%	1,056,937	24,021	-3.8%
Forest Products	19,355	8.8%	826,387	18,782	2.4%
Grain	33,821	11.6%	1,211,022	27,523	-6.9%
Metallic Ores and Metals	42,907	1.3%	1,991,946	45,272	-1.2%
Motor Vehicles and Parts	28,020	10.6%	1,113,962	25,317	2.9%
Nonmetallic Minerals and Products	44,901	15.1%	1,827,434	41,533	7.1%
Petroleum and Petroleum Products	20,902	10.7%	899,404	20,441	26.0%
Other	10,283	10.7%	420,088	9,547	-5.8%
Intermodal Units	328,059	14.9%	13,680,199	310,914	3.9%
Total Traffic	717,738	9.4%	30,205,682	686,493	1.9%

¹ Average per week figures may not sum to totals as a result of independent rounding.

Trends, 2013 vs 2012

North America



Major Rail Traffic Groups And the Associated *Weekly Railroad Traffic* Commodity Categories

Chemicals
Chemicals
Coal
Coal
Farm and Food Products, Excl. Grain
Farm Products, Excluding Grain
Grain Mill Products
Food & Kindred Products
Forest Products
Primary Forest Products
Lumber & Wood Products
Pulp, Paper & Allied Products
Grain
Grain
Metallic Ores and Metals
Metallic Ores
Coke
Metals & Products
Iron & Steel Scrap
Motor Vehicles and Parts
Motor Vehicles & Parts
Nonmetallic Minerals and Products
Crushed Stone, Sand & Gravel
Nonmetallic Minerals
Stone, Clay & Glass Products
Petroleum and Petroleum Products
Petroleum Products
Other
Waste & Nonferrous Scrap
All Other Carloads
Intermodal
Containers
Trailers

Weekly traffic data for the detailed commodity groups are available in the AAR's *Weekly Railroad Traffic* report, which can be ordered at <https://www.aar.org/Pages/ProductDetails.aspx?ProductCode=WRT2013>. Monthly traffic data for the detailed commodity groups are available in our *Rail Time Indicators* report, which costs \$50 for 12 monthly issues. RTI can also be purchased with a spreadsheet containing monthly traffic data by country and commodity for \$100. *Rail Time Indicators* may be ordered at www.aar.org/Pages/AllProducts.aspx.