

UNITED STATES PATENT AND TRADEMARK OFFICE

BEFORE THE PATENT TRIAL AND APPEAL BOARD

PROFRAC HOLDING CORPORATION and
U.S. WELL SERVICES, LLC,
Petitioner,

v.

HALLIBURTON ENERGY SERVICES, INC.,
Patent Owner.

Case IPR2023-01319
Patent No. 7,841,394 B2

DECLARATION OF DR. ROBERT A. DURHAM

TABLE OF CONTENTS

I.	INTRODUCTION & QUALIFICATIONS	1
II.	TASK SUMMARY AND MATERIALS REVIEWED	6
III.	LIST OF EXHIBITS.....	6
IV.	SUMMARY OF CONCLUSIONS.....	9
V.	LEGAL STANDARDS.....	10
A.	Level of Ordinary Skill in the Art	10
B.	Legal Standard for Claim Construction	11
C.	Obviousness.....	12
D.	Priority Date	15
VI.	OVERVIEW OF THE '394 PATENT.....	17
VII.	LEVEL OF ORDINARY SKILL IN THE ART	19
VIII.	CLAIM CONSTRUCTION	20
IX.	TECHNOLOGY BACKGROUND AND STATE OF THE ART	20
A.	Oil and Gas Well Drilling.....	22
1.	Drilling Equipment and Contractors.....	24
B.	Well Completion.....	27
1.	Casing and Cementing	27
2.	Well Stimulation.....	30
a.	Acidizing.....	31
b.	Hydraulic Fracturing.....	32
3.	Completion Equipment and Contractors.....	37
4.	Flowback.....	41
C.	Oil and Gas Production	41
1.	Collection Equipment	42
2.	Separation and Storage Facilities.....	48
3.	Production Chemicals	50
4.	Well Maintenance.....	51
X.	OVERVIEW OF THE PRIOR ART	55

A.	Crossley (Ex. 1005).....	55
B.	Albers (Ex. 1006)	60
C.	Lehman (Ex. 1009).....	62
XI.	GROUND 1: CROSSLEY IN VIEW OF ALBERS DOES NOT RENDER THE CLAIMS OF THE '394 PATENT OBVIOUS.....	62
A.	The Petition Does Not Establish A Motivation to Combine Crossley and Albers.....	63
B.	The Petition Does not Establish a Reasonable Expectation of Success in Combining Crossley and Albers.....	71
C.	Crossley Teaches Away From the Petition's Proposed Combination of Crossley and Albers	79
D.	The Combination of Crossley and Albers Does Not Disclose, Teach, or Suggest All Limitations of the Claims of the '394 Patent	89
1.	Independent Claim 1	89
a.	The combination of Crossley and Albers does not disclose or suggest limitation 1[d].....	89
b.	The combination of <i>Crossley</i> and <i>Albers</i> does not disclose, teach, or suggest limitation 1[e]	97
2.	Dependent Claim 2.....	100
3.	Dependent Claim 3.....	100
4.	Dependent Claim 4.....	101
5.	Dependent Claim 5.....	101
6.	Dependent Claim 6.....	101
7.	Dependent Claim 7.....	103
8.	Dependent Claim 8.....	103
9.	Dependent Claim 9.....	105
10.	Dependent Claim 10	106
11.	Dependent Claim 11.....	106
12.	Dependent Claim 12	109
13.	Dependent Claim 13	110

14.	Dependent Claim 14	110
15.	Dependent Claim 15	111
16.	Dependent Claim 16	111
17.	Dependent Claim 17	115
18.	Dependent Claim 18	115
19.	Dependent Claim 19	116
20.	Dependent Claim 20	117
21.	Dependent Claim 21	118
22.	Dependent Claim 22	118
23.	Dependent Claim 23	118
24.	Independent Claim 24	118
25.	Independent Claim 25	119
26.	Independent Claim 26	120
27.	Independent Claim 27	120
XII.	GROUND 2: LEHMAN DOES NOT CURE THE FAILURES OF CROSSLEY AND ALBERS FOR DEPENDENT CLAIMS 11 AND 13.....	124
XIII.	CONCLUSION.....	127

I, Robert Durham, hereby declare as follows:

I. INTRODUCTION & QUALIFICATIONS

1. I have been retained on behalf of Halliburton Energy Services, Inc. (“Halliburton”) to provide my opinions regarding ProFrac Holding Corporation and U.S. Wells Services, LLC’s Petition for *Inter Partes* Review of Claims 1-27 of U.S. Patent No. 7,841,394 (“the ’394 Patent”). I submit this declaration based on my personal knowledge.

2. In formulating my opinions, I have relied upon my knowledge, training, and experience in the relevant art. My qualifications are stated more fully in my curriculum vitae, which has been provided as Appendix A. My CV also lists publications on which I am a named author and identifies parties on behalf of whom I have previously provided expert testimony within the past four years. Here, I provide a brief summary of my qualifications.

3. I am a consulting engineer with experience in a number of technical areas. I have expertise in the oil and gas industry ranging from drilling, completion, and production operations to downstream operations. I have been working with oil field production companies, refining and chemical plants and equipment manufacturers and technology development companies, as a consultant, for nearly twenty years. My work relates to the subject matter of the ’394 Patent, which I describe below in Section VI (“Overview of the ’394 Patent”).

4. I received my Bachelor of Science in Electrical Engineering and Master of Engineering and Technology Management from the University of Tulsa in 1992 and 1997, respectively. After years of professional work and research, I received my Ph.D. in Engineering Management from Kennedy Western University in 2004.

5. I have also served in positions of leadership in the Petroleum and Chemical Industry Committee (“PCIC”) of the Institute of Electrical and Electronics Engineers (“IEEE”) for nearly twenty years. IEEE is the world’s largest technical professional association. The PCIC is the premier forum for the exchange of electrical applications technology related to the petroleum and chemical industry. From 2005 to 2012, I served as secretary, then vice chair and then ultimately chair of the Production Subcommittee of the PCIC. The Production Subcommittee is the primary method for PCIC members to communicate technical papers related to drilling, well head and facilities operations of oil and gas wells. In 2013, I was appointed as Vice-Chair of the Standards Subcommittee of the PCIC, a role which transitioned to Chair in 2014. I served as Chair until 2022. The Standards subcommittee of the PCIC is the Sponsor of IEEE standards relating to electrification and electrical equipment operations in the Oil and Gas Industry. The PCIC Standards Subcommittees sponsors nearly 50 electrical and oil and gas related standards. In September 2022, I was elected as an Executive Officer of the PCIC. I will serve as an Executive Officer for a total of eight years, serving two-year terms

in each of the following positions: Secretary; Vice Chair; Chair; and Chair of Advisory and Awards.

6. My peers have recognized my contributions, particularly in the area of electrical equipment in the oil and gas industry. Because of this recognition, in 2019, I was elevated to the grade of Fellow of the IEEE for “contributions to submersible electrical equipment analysis and multi-point ground methods in hazardous petroleum and chemical environments.” The IEEE Fellow grade is limited to the top 0.1% of the membership of IEEE worldwide.

7. I have worked directly in the area of electrification of oil and gas fields both as an employee and as a consulting engineer. From 2000 until the end of 2002, I was employed as Manager of Electric Infrastructure for New Dominion, LLC (“NDL”). In that capacity, I administratively owned and was responsible for all electrical equipment including overhead power lines, transformers, switchgear, drives and motors throughout NDL’s production, exploration and drilling areas.

8. After a brief stint as Vice President for EDG Power Group, responsible for Engineering and Project Management of generation and co-generation facilities across the U.S., I transitioned to the role of consulting engineer. In that role, I have served as consulting engineer relating to the design, construction, and analysis of all kinds of power systems, especially those in the oil and gas industry. This has included not only design and selection of equipment but also analysis of failures of

equipment in the oil and gas field from drilling / completion sites to production facilities, midstream and downstream (refinery) locations.

9. In addition, I am a principal of PEDOCS, Inc., an oil and gas production company operating over 50 oil and gas production wells in Oklahoma. As such, I am familiar with operations of oil and gas wells including well stimulation, completion, hydraulic fracturing and production.

10. I have been familiar with oil and gas drilling, completion (including fracturing (fracking)), production, midstream and downstream operations for over twenty years. In addition to being responsible for interfacing with drilling and fracturing operations with regards to electrical needs as an employee of NDL, I have been further educated about drilling, fracturing, production and other oil and gas operations as I have consulted and investigated incidents on multiple well drilling, fracturing, completion, production, midstream and downstream sites over my engineering consulting engagements.

11. I have been familiar with power distribution, including generation, transmission, and distribution equipment. As an employee, I worked as a design and construction engineer for generation facilities for Central and Southwest (now American Electric Power (“AEP”)). I was also responsible for design and construction of generation facilities when employed by EDG Power Group, as discussed above. While at AEP, I spent three years as a transmission planner,

responsible for modeling transmission systems and developing plans for increased power distribution capacities at high voltages. While at NDL, I owned and was responsible for design, construction and maintenance of several hundred miles of medium voltage (5 – 25 kV) distribution lines, switchgear, drives and motors used for oil and gas drilling, completion and production. Over the last ~ 20 years, I have consulted with numerous clients ranging from utilities to oil and gas development and production companies on the design, upgrades and maintenance of generation and power distribution facilities.

12. I have been familiar with Occupational Safety and Health Administration (“OSHA”) and its responsibilities at oil and gas locations. I have consulted and investigated incidents on multiple oil and gas sites where OSHA has also performed investigations with regard to injuries and fatalities that have occurred at oil and gas locations, including drilling, fracturing and completion operations. As Principal Scientist of THEWAY Labs, part of my responsibilities includes overseeing the Health Safety and Environmental (“HSE”) program at THEWAY Labs, and establishing policies and procedures commensurate with OSHA requirements at all locations, including requirement for oil and gas sites.

13. I am the author or co-author of over fifty published papers and five books. A list of publications that I have authored over the last thirty years is included in my professional CV, which is attached as Appendix A.

14. Therefore, based on my education, professional experience of over 30 years, and scholarly books and publications, I am an expert in the relevant field of the Asserted Patents at issue here and have been an expert in this field since before the Asserted Patents were filed with the United States Patent and Trademark Office (“USPTO”). I am familiar with how a person having ordinary skill in the art would have understood and used the terminology found in the Asserted Patents at the time of their filing.

II. TASK SUMMARY AND MATERIALS REVIEWED

15. I have been asked to review the Petition for *Inter Partes* Review of Claims 1-27 of the '394 Patent along with the '394 Patent, its file history, the asserted prior art, and other associated exhibits and to provide my opinions regarding the Petition and grounds asserted therein. In forming my opinions, I have reviewed the materials cited in the List of Exhibits and the materials cited throughout my declaration.

III. LIST OF EXHIBITS

16. In forming my opinions, I have reviewed the '394 Patent, its prosecution history and references cited by the Examiner, the materials cited in the List of Exhibits, and the materials cited throughout my declaration.

No.	Petitioner's Exhibits
1001	U.S. Patent No. 7,841,394
1002	File History of U.S. Patent No. 7,841,394

1003	Declaration of Dr. Michael Nikolaou
1004	Curriculum Vitae of Dr. Michael Nikolaou
1005	WIPO Publication No. 2005/111369 A1 to Crossley (“Crossley”)
1006	U.S. Patent No. 7,451,820 to Albers et al. (“Albers”)
1007	U.S. Patent No. 4,397,353 to Lacy (“Lacy”)
1008	WIPO Publication No. WO2007/024383A2 to Tolman (“Tolman”)
1009	U.S. Patent App. Pub. No. 2004/0050550 A1 to Lehman et al. (“Lehman”)
1010	S. Dalvi, Fundamentals of Oil & Gas Industry for Beginners (Notion Press 2015) (excerpts)
1011	U.S. Patent App. Pub. No. 2013/0306322 to Sanborn et al.
1012	U.S. Patent No. 9,410,410 to Broussard et al.
1013	U.S. Patent App. Pub. No. 2012/0255734 to Coli et al.
1014	U.S. Patent No. 3,560,053 to Ortloff
1015	U.S. Patent No. 3,664,422 to Bullen
1016	Claim Construction Order
1017	WD Texas Statistics

No.	Patent Owner’s Exhibits
2001	U.S. Patent No. 4,077,428 to Weaver (“Weaver”)
2002	Joint Claim Construction Brief
2003	U.S. Patent No. 3,933,205 to Kiel (“Kiel”)
2005	Deposition Transcript of Dr. Michael Nikolaou, dated June 6, 2024
2006	Bourgoyne, Adam T., Jr., Keith K. Millheim, Martin E. Chenevert, and F.S. Young, Jr., <i>Applied Drilling Engineering</i> , Society of Petroleum Engineers (1986).
2007	Staff of Royal Dutch / Shell Group of Companies, <i>The Petroleum Handbook</i> , (1983).
2008	Rahman, S. S. and G. V. Chilingarian, <i>Casing design-theory and practice</i> (1995).

2009	Manrique, E.J., J.L. Mogollon, J.A. Linares, and M. Farrera, <i>Basic Nitrogen Compounds in Crude Oils: Effect on Mineral Dissolution during Acid Stimulation Processes</i> , International Symposium on Oilfield Chemistry (1997).
2010	Michael Morton, <i>Unlocking the Earth: A Short History of Hydraulic Fracturing</i> , GEO ExPro, Vol. 10, No. 6, December 2013 (available at https://geoexpro.com/unlocking-the-earth-a-short-history-of-hydraulic-fracturing/) (last accessed July 17, 2023).
2011	Carl T. Montgomery and Michael B. Smith, <i>Hydraulic Fracturing: History of an Enduring Technology</i> , Journal of Petroleum Technology vol. 62 issue 12 (Dec. 2010).
2012	Grieser, B., et al., <i>The Rocket Science Behind Water Frac Design</i> , SPE Production and Operations Symposium, Oklahoma City, OK (March 2003).
2013	Van Domelen, M. S., et al., <i>State-of-the-Art Fracturing in the North Sea</i> , Offshore Technology Conference (1995).
2014	Stephenson, SV, EL Woodall, CD Donaghe, and RE Dant. <i>Fracturing Process Control and Automation: Phase 2</i> , (1993).
2015	L.P. Moore, L.P. and H. Ramakrishnan,, <i>Restimulation: Candidate Selection Methodologies and Treatment Optimization</i> , SPE Annual Technical Conference (2006).
2016	IEEE RP 1017, “IEEE Recommended Practice for Field Testing Electric Submersible Pump Cable” (2004).
2017	Swanson, T. A., et al, <i>The Successful Use of Both Kinetic Hydrate and Paraffin Inhibitors Together in a Deepwater Pipeline with a High Water Cut in the Gulf of Mexico</i> , SPE International Symposium on Oilfield Chemistry (2005).
2018	Chen, Huey J., Gene Kouba, and Seong Lee, <i>Optimizing Corrosion Inhibitor Injection Rate in Flow Lines</i> , CORROSION (2003).
2019	Pizzarelli, S. G., O. E. Gonzalez, P. Justiniano, S. A. Olivares, and J. J. Potma, <i>Results of Thermal Horizontal Completions with Sand Control in Lake Maracaibo, Venezuela: Case Histories of Horizontal Gravel Packs in Bachaquero-01 Reservoir</i> , SPE International Thermal Operations and Heavy Oil Symposium and International Horizontal Well Technology Conference (2002).

2020	Chike, Uchendu, Obadare Awoleke, and Nwoke Linus, <i>Solvent / Acid Blend Provides Economic Single Step Matrix Acidizing Success for Fines and Organic Damage Removal in Sandstone Reservoirs: A Niger - Delta Case Study</i> , SPE Annual Technical Conference and Exhibition (2004).
2021	Conaway, Charles F, <i>The Petroleum Industry: A Nontechnical Guide</i> . Pennwell Books (1999).
2022	Braek, A. M., R. A. Almehaideb, and R. Hughes, <i>Application of Eos to Optimize the Design of an Early Production Scheme of an Onshore Oil Field in Abu Dhabi</i> , Abu Dhabi International Petroleum Exhibition and Conference (1998).
2023	Belden Master Catalog (2003).

IV. SUMMARY OF CONCLUSIONS

17. Based upon my review of the Petition and materials identified above, it is my opinion that the Petition has failed to establish that a person of ordinary skill in the art (“POSITA”) would have been motivated to combine *Crossley* and *Albers* as proposed in the Petition with a reasonable expectation of success. It is further my opinion that the Petition has failed to establish that a POSITA would have been motivated to further combine *Lehman* with *Crossley* and *Albers* as proposed in the Petition with a reasonable expectation of success.

18. It is further my opinion that, when considered as a whole, *Crossley* would have led a POSITA away from the combination of *Crossley* and *Albers* as proposed in the Petition and thus away from the claims of the ’394 Patent.

19. It is also my opinion that the combination of *Crossley* and *Albers* (or the combination of *Crossley*, *Albers*, and *Lehman* in the case of dependent claims 11 and 13) does not disclose all limitations of claims 1-27 of the '394 Patent.

V. LEGAL STANDARDS

A. LEVEL OF ORDINARY SKILL IN THE ART

20. When interpreting a patent, I understand that it is important to identify the relevant art pertaining to the patent-in-suit as well as the level of ordinary skill in that art at the time of the claimed invention. The “art” is the field of technology to which the patent is related.

21. I have been instructed by counsel that the POSITA is a hypothetical person who is presumed to know the relevant prior art. I understand that the actual inventor’s skill is not determinative of the level of ordinary skill. I further understand that the factors that may be considered in determining the level of skill include: the types of problems encountered in the art; prior art solutions to those problems; rapidity with which innovations are made; sophistication of the technology; and educational level of active workers in the field. I understand that not all such factors may be present in every case, and one or more of them may predominate.

B. LEGAL STANDARD FOR CLAIM CONSTRUCTION

22. I understand that the first step in determining whether a patent claim would have been obvious is to ascertain how a POSITA would have understood the claim terms.

23. I have been instructed by counsel on the law regarding claim construction and patent claims, and I understand that a patent may include two types of claims: independent claims and dependent claims. An independent claim stands alone and includes only the limitations it recites. A dependent claim can depend from an independent claim, or it can further depend from another dependent claim. I understand that a dependent claim includes all the limitations that it recites, in addition to all the limitations recited in the claim(s) from which it depends.

24. It is my understanding that in proceedings before the USPTO, the claims of a patent are to be construed under what is referred to as the “Phillips standard.” I understand that this means that claim terms of a patent are given the meaning the terms would have to a POSITA, in view of the description provided in the patent itself and the patent’s file history.

25. I understand that to determine how a person of ordinary skill would understand a claim term, one should look to those sources available that show what a person of skill in the art would have understood the disputed claim language to mean. I understand that, in construing a claim term, one looks primarily to the

intrinsic patent evidence, including the words of the claims themselves, the remainder of the patent, and the patent's prosecution history. I understand that extrinsic evidence, which is evidence external to the patent and the prosecution history, may also be useful in interpreting patent claims when the intrinsic evidence itself is insufficient.

26. I understand that words or terms should be given their ordinary and accepted meaning unless it appears that the inventors were using them to mean something else. In making this determination, the claims, the remainder of the patent, and the prosecution history are of paramount importance. Additionally, the patent and its prosecution history must be consulted to confirm whether the patentee has acted as its own lexicographer (i.e., provided its own special meaning to any disputed terms), or intentionally disclaimed, disavowed, or surrendered any claim scope.

27. In comparing the claims of the '394 Patent to the prior art, I have considered the '394 Patent and its file history in light of the understanding of a POSITA at the time of the alleged invention.

C. OBVIOUSNESS

28. I understand that the prior art may render a patent claim "obvious." I understand that two or more prior art references (e.g., prior art articles, patents, or publications) that each disclose fewer than all elements of a patent claim may

nevertheless be combined to render a patent claim obvious if the combination of the prior art collectively discloses all elements of the claim and one of ordinary skill in the art at the time would have been motivated to combine the prior art in such a way. I understand that this motivation to combine need not be explicit in any of the prior art, but may be inferred from the knowledge of one of ordinary skill in the art at the time the patent was filed. I also understand that one of ordinary skill in the art is not an automaton, but is a person having ordinary creativity. I further understand that one or more prior art references that disclose fewer than all of the elements of a patent claim may render a patent claim obvious if including the missing element would have been obvious to one of skill in the art (e.g., the missing element represents only an insubstantial difference over the prior art or a reconfiguration of a known system).

29. I understand that under the doctrine of obviousness, a claim may be invalid if the differences between the invention and the prior art are such that the subject matter as a whole would have been obvious at the time the invention was made to a POSITA to which the subject matter pertains.

30. To assess obviousness, I understand that I am to consider the scope and content of the prior art, the differences between the prior art and the claim, the level of ordinary skill in the art, and any secondary considerations to the extent they exist. I understand that hindsight must not be used in an obviousness analysis and that one

must consider only what was known at the time of the invention. I understand that reliance on any knowledge that is gleaned only from patent owner's disclosure constitutes impermissible hindsight. I also understand that impermissible hindsight must be avoided, and any determination of obviousness must be reached on the basis of the facts gleaned from the prior art.

31. I understand that in considering whether a claimed invention is obvious, one must consider whether, at the time of the claimed invention, there was a reason that would have prompted a person having ordinary skill in the field of the invention to combine the known elements in the prior art in a way the claimed invention does, taking into account such factors as (1) whether the claimed invention was merely the predictable result of using prior art elements according to their known function(s); (2) whether the claimed invention provides an obvious solution to a known problem in the relevant field; (3) whether the prior art teaches or suggests the desirability of combining elements claimed in the invention; (4) whether the prior art teaches away from combining elements in the claimed invention; (5) whether it would have been obvious to try the combinations of elements, such as when there is a design incentive or market pressure to solve a problem and there are a finite number of identified, predictable solutions. In order to find an invention obvious, one must find that the prior art provided a reasonable expectation of success. I understand that obvious to try is not sufficient in unpredictable technologies.

32. It is also my understanding that there are additional considerations that may be used as further guidance as to when the above factors will result in a finding that a claim is obvious, including the following:

- the claimed subject matter is simply a combination of prior art elements according to known methods to yield predictable results;
- the claimed subject matter is a simple substitution of one known element for another to obtain predictable results;
- the claimed subject matter uses known techniques to improve similar devices or methods in the same way;
- the claimed subject matter applies a known technique to a known device or method that is ready for improvement to yield predictable results;
- the claimed subject matter would have been “obvious to try” choosing from a finite number of identified, predictable solutions, with a reasonable expectation of success;
- there is known work in one field of endeavor that may prompt variations of it for use in either the same field or a different one based on design incentives or other market forces if the variations would have been predictable to a POSITA;
- there existed at the time of the invention a known problem for which there was an obvious solution encompassed by the patent’s claims; and
- there is some teaching, suggestion, or motivation in the prior art that would have led a POSITA to modify the prior art reference or to combine prior art reference teachings to arrive at the claimed subject matter.

D. PRIORITY DATE

33. I understand that the asserted “priority date” of a patent is generally the date on which a patent application is filed. I further understand that, in some

instances, a patent may be entitled to an earlier priority date if a party shows either: (i) an earlier actual reduction to practice of the invention claimed in the patent or (ii) an earlier conception of the invention claimed in the patent followed by a diligent reduction to practice of that invention.

34. I understand that conception is the formation in the mind of the inventor of a definite and permanent idea of the complete and operative invention. I further understand that, to have been conceived, the idea must be so clearly defined in the inventor's mind that only ordinary skill would be necessary to reduce the invention to practice, without extensive research or experimentation. I also understand that conception must be proved by corroborating evidence, not merely an inventor's testimony. Conception may be proven when the invention is shown in its complete form by drawings, disclosure to another person, or other forms of evidence.

35. I understand that the purpose of the diligence requirement is to show that the invention was not abandoned, set aside, or unreasonably delayed. I further understand that the inventor need only exercise reasonably continuous diligence until reduction to practice. Diligence means working continuously, though not necessarily every day. I also understand that the filing of a patent application is a constructive reduction to practice.

36. I understand that it is the burden of the party challenging the patent to show that the alleged prior art is, in fact, prior art.

VI. OVERVIEW OF THE '394 PATENT

37. U.S. Patent Application No. 11/291,496 (the “’496 Application”) leading to the ’394 Patent was filed on December 1, 2005. As the Petition acknowledges, and does not dispute, “Patent Owner represented during the prosecution underlying the ’394 Patent that it is entitled to a priority date of August 5, 2005.”¹

38. The background of the ’394 Patent explains that “[t]he servicing and stimulation of wells can require a series of coordinated operations that begin with the supply by truck of equipment, supplies, fuel, and chemicals to the wellhead.”² “The equipment is then set up and made ready with proppant and chemicals.”³ “After completion of the well services, equipment must be broken down and made ready for transport to the next pad for service.”⁴

¹ Petition at 3; Ex. 1002 at 632-658.

² Ex. 1001 at 1:24-27.

³ Ex. 1001 at 1:27-28.

⁴ Ex. 1001 at 1:28-30.

39. The '394 Patent explains that “[t]his movement of equipment and supplies has environmental impacts, and the exposure of mobile equipment to adverse weather conditions can jeopardize well treatment operations and worker safety.”⁵ To address these concerns, the '394 Patent relates to “methods and apparatuses for simultaneously treating multiple wells from a centralized location and simultaneously connecting multiple wells to a single manifold, so as to conserve labor, infrastructure, and environmental impact.”⁶

40. The '394 Patent discloses systems for centralized well operations that include a well treatment operations factory which manufactures and pumps a well stimulation fluid, a first connection between a first location (*e.g.*, a well, pad, or plurality of pads) and the factory, and a second connection between a second location (*e.g.*, a well, pad, or plurality of pads) and the factory.⁷

41. The systems for centralized well operations also include a means for simultaneously flowing a first stimulation fluid to the first location (and not the second location) and a second stimulation fluid to the second location (and not the

⁵ Ex. 1001 at 1:35-38.

⁶ Ex. 1001 at 1:7-11.

⁷ Ex. 1001 at 1:61-66, Cl. 1-27.

first location).⁸ The '394 Patent discloses that the stimulation fluids can be “any combination of proppant, fracturing fluid, gelling agent, friction reducer, and acid.”⁹ The majority of the claims require that the first stimulation fluid and the second stimulation fluid have different compositions.¹⁰

VII. LEVEL OF ORDINARY SKILL IN THE ART

42. Petitioner asserts that a POSITA “would have had at least a Bachelor of Science in chemical engineering, mechanical engineering, materials science, or metallurgical engineering or an equivalent field and at least two years of academic or industry experience in the oil and gas industry, including experience with process control systems. A person having education but less professional experience, and vice versa, may qualify also qualify as a POSITA.”¹¹ I generally agree with Petitioner’s definition of a POSITA. However, I believe that Petitioner’s definition of a POSITA is too broad in that it includes those with materials science and metallurgical engineering degrees. In my opinion, these particular degrees are not relevant to the subject matter of the '394 Patent.

⁸ Ex. 1001 at 1:66-2:3.

⁹ Ex. 1001 at 2:3-5.

¹⁰ Ex. 1001 at Cl. 1-26.

¹¹ Petition at 3-4.

VIII. CLAIM CONSTRUCTION

43. I understand that the parties have agreed to construe a single term used in the claims of the '394 Patent in the related district court case, as shown in the table below.

Claim Terms / Associated Claims	Agreed Term Construction
“means for simultaneous flowing” Claims 1, 24-27	Subject to 35. USC 112, ¶6 (pre-AIA) Function: simultaneous flowing Corresponding Structure: a manifold and equivalents thereof

44. I have applied this claim construction in my analysis below. It is my opinion that a POSITA would understand all the other claim terms to have their plain and ordinary meaning, and I have applied the plain and ordinary meaning, in the context of the '394 Patent, for all other claim terms.

IX. TECHNOLOGY BACKGROUND AND STATE OF THE ART

45. In the subsections below, I describe some of the basic principles of engineering that would be used, or at least considered for use, in the field of oil and gas operations, and particularly in the field of fluid handling and control systems. The principles discussed in the subsections below would have been known to a POSITA in the December 2005 timeframe. I understand that it is important, when viewing the State of the Art and the background technology known to a POSITA, to

rely on those materials which would have been known to a POSITA as of the priority date of the '394 Patent. Reliance on materials published or made publicly available after the priority date the '394 Patent (with the exception of publications specifically documenting the history of an industry) does not show what would have been known to a POSITA in the relevant timeframe. For example, reliance on art published in the 2013 timeframe (such as Sanborn (Ex. 1011)) to demonstrate what was known to a POSITA is an example of hindsight. Hindsight must be avoided when showing the state of the art or the background of technology known in the relevant timeframe (i.e., December 2005).

46. I note that Dr. Nikolaou engages in hindsight throughout his background and State of the Art section, as well as in his analysis of the validity of the claims of the '394 Patent. I note Dr. Nikolaou relies on at least the following references, published long after the priority date of the '394 Patent, as examples of his hindsight-based analysis:

Reference	Publication Date
<i>Tolman</i>, Ex. 1008	March 1, 2007
<i>Dalvi</i>, Ex. 1010	2015
<i>Sanborn</i>, Ex. 1011	November 21, 2013
<i>Broussard</i>, Ex. 1012	May 22, 2014
<i>Coli</i>, Ex. 1013	October 11, 2012

47. Accordingly, Dr. Nikolaou fails to demonstrate what would have been the basic technological background and State of the Art known to a POSITA at the time of the '394 Patent, as compared to what was known, for example, in 2012. The period of time between 2005 and 2012, for example, was a period of substantial technological growth, particularly in the area of well stimulation to which the claims of the '394 Patent are directed.

A. OIL AND GAS WELL DRILLING

48. Oil and gas exploration and production operations depend on identifying, locating and collecting hydrocarbon (i.e., oil and gas (natural gas)) reserves for sale, use as a fuel, for lubrication, or for the development of chemicals, pharmaceuticals and plastics used in modern society. Rotary drilling techniques, where a drill stem is spun and a drill bit cuts into the rock had been used as far back as the Egyptian era but had limited use until the invention of the roller cone drill bit in 1908 by Howard Hughes. In a rotary drilling system, the drill bit cuts or pulverizes the rock. A fluid, known as drilling mud, is circulated down the hollow drill stem, out orifices in the bit and then up the annulus, or the area between the drill stem and

the wellbore walls. The drill mud serves the dual purpose of lubricating and cooling the bit teeth and grinding surfaces, as well as carrying detritus from the drilling process out of the hole and to the surface where it is observed for its characteristics (logged), collected (shale shakers) and discarded.¹²

49. Traditional well drilling techniques, including both cable tool and rotary, focused on attempting to keep wells vertical, and maintain a “straight hole” in order to reach the target formation at a known location. However, this means that the hydrocarbon bearing formation is only exposed to the wellbore for only the vertical depth of the formation at the wellbore location which is often only tens of feet. Further, surface drilling locations must be directly above the target formations limiting access to those formations which are located under geographical features (such as lakes, mountains, oceans), buildings or other environs which would prevent, or make difficult, the location of a traditional drilling pad.¹³

50. Directional drilling is a technique for accessing hydrocarbon bearing formations (oil and gas formations) that are not located immediately beneath the surface location. Some tool or process is used to cause the well bore to deviate from the vertical in order to reach previously inaccessible formation locations, to expose

¹² See generally Ex. 2021 at pp. 97-127.

¹³ See generally Ex. 2021 at pp. 97-127.

more of the hydrocarbon bearing formation to the well bore, or to drill several wells from a single surface location, such as an offshore platform or a land-based drilling pad.¹⁴

51. According to *Bourgoyne*, “[d]irectional drilling is the process of directing the well-bore along some trajectory to a predetermined target. Deviation control is the process of keeping the wellbore contained within some prescribed limits relative to inclination angle, horizontal excursion from the vertical, or both.”¹⁵

52. Directional drilled wells usually involve a vertical section of the well that is reached using conventional, rotary drilling techniques. Once the kick point is reached, “some method must be used to force the bit in the desired direction.” Regardless of what tool is used to cause the deviation “the principles for determining the total angle change, dogleg severity, new inclination angle, direction and tool-face setting are all the same.”¹⁶

1. Drilling Equipment and Contractors

53. Drilling equipment consists of large, transportable rigs with derricks necessary to raise the drilling and casing pipe strings, raised platforms (rig floor) for

¹⁴ See generally Ex. 2021 at pp. 97-127.

¹⁵ Ex. 2006 at § 8.6.

¹⁶ Ex. 2006 at § 8.6.

working above the well, large pits to hold drilling fluids (i.e. drilling mud), and large pumps to pump the drilling fluid downhole. As of 2005, the vast majority of rigs were hydraulically operated with diesel generators providing power to operate the hydraulic pumps, such as the one shown below:¹⁷

¹⁷ Ex. 2007 at p. 124.

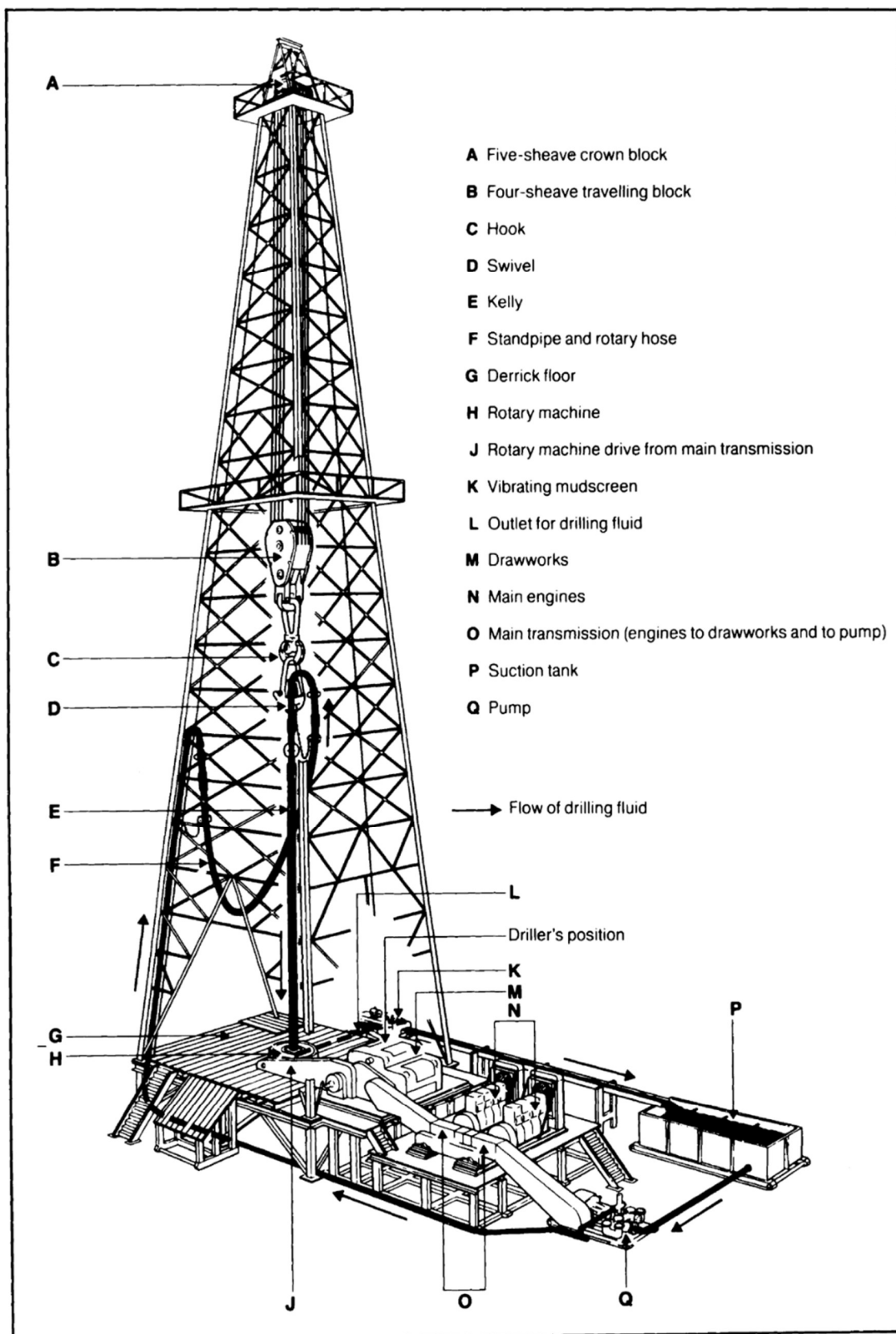


Figure 3.68a **Diagram of rotary drilling rig**

54. Specialty contractors provided well drilling services, including equipment and personnel to perform drilling. These contractors were often unique to the drilling segment of the oil and gas industry, with little carryover into other areas such as completion and production. Examples of drilling contractors that were active at the time of the '394 Patent are Helmerich & Payne (H&P), Nabors Drilling, Drilling Systems (UK) LTD and Parker Drilling.

B. WELL COMPLETION

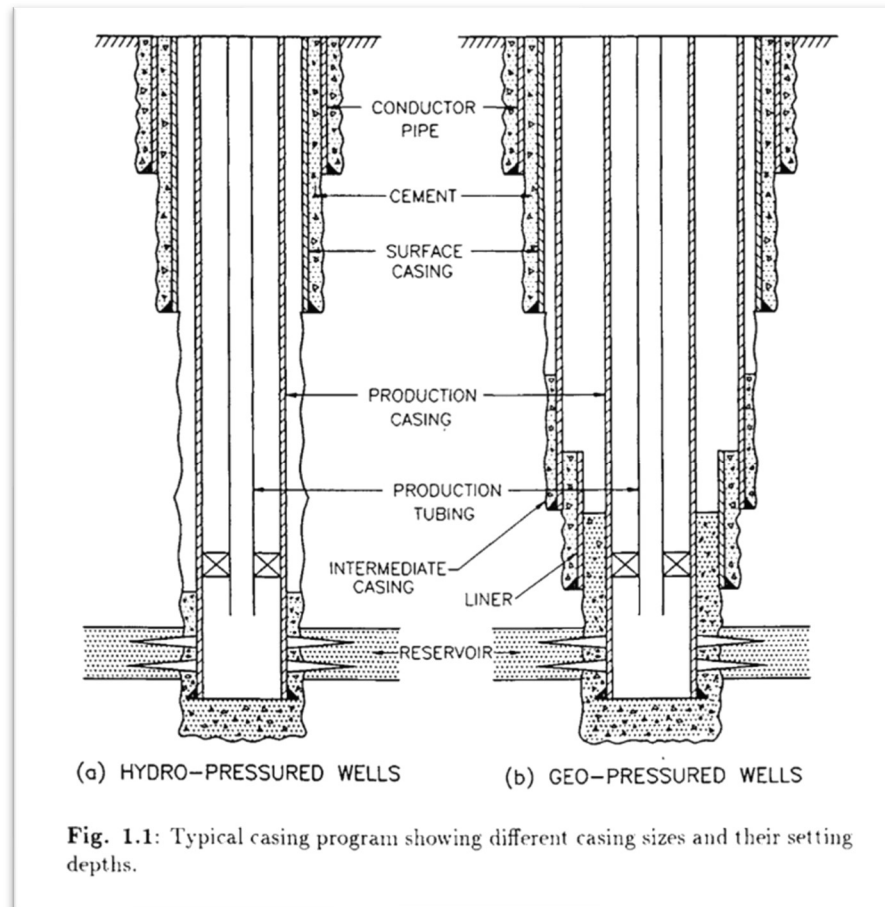
1. Casing and Cementing

55. Once a wellbore has been drilled, casing is added to the wellbore. Casing is a series of tubular structures (pipes) inserted into the well that are used to isolate the wellbore from the surrounding geological formations. Casing provides several functions in the wellbore, as explained by Rahman in 1995:¹⁸

1. Keeping the hole open by preventing the weak formations from collapsing, i.e., caving of the hole.
2. Serving as a high strength flow conduit to surface for both drilling and production fluids.
3. Protecting the freshwater-bearing formations from contamination by drilling and production fluids.
4. Providing a suitable support for wellhead equipment and blowout preventers for controlling subsurface pressure, and for the installation of tubing and subsurface equipment.
5. Providing safe passage for running wireline equipment.
6. Allowing isolated communication with selectively perforated formation(s) of interest.

¹⁸ Ex. 2008 at p. 1.

56. There are several different strings of tubular structures inserted into a well that, as a group, are referred to as casing. These are demonstrated in Fig. 1.1 from Rahman:¹⁹



57. The conductor pipe is the topmost, and outermost, layer of the casing string. It is set first and is designed to hold back the loosely consolidated surface formations (such as topsoil) and prevent them from caving into the hole. The next layer is the surface casing. The surface casing's primary role is to isolate relatively

¹⁹ Ex. 2008 at p. 2.

shallow freshwater formations from the wellbore and prevent them from being contaminated by drilling / completion fluids or from produced fluids. The surface casing extends from the surface to a solid consolidated formation (typically a limestone) and provides a seal between that formation and the surface, isolating the shallow water and loosely consolidate formations from the wellbore. As shown in Fig. 1.1, both the surface casing and the conductor pipe are cemented into the wellbore all the way to the surface.²⁰

58. In many wells, some of the overburden formations (formations above the target formation) have properties which prevent proper drilling to continue. In some cases, these non-producing formations are loosely consolidated and tend to cave-in the hole. In other formations, saltwater or other fluids can penetrate the well or the natural fractures and properties in the overburden formation absorb the drilling fluid, resulting in lost circulation. These formations are isolated from the wellbore by the use of strings of “intermediate casing.” Each string of intermediate casing is cemented at the bottom of the string to prevent migration of well fluids up the annulus of the casing (between the casing and the formation).²¹

²⁰ Ex. 2008 at pp. 1-6.

²¹ Ex. 2008 at pp. 1-6.

59. Once the target formation has been reached, a string of production casing is run, and is the final string of “casing.” This casing is cemented above and below the target formation to prevent the migration of the hydrocarbons out of the target formation to other formations surrounding it. Further, additional cement can be pumped above the target formation to provide additional mechanical support for the casing string. In some modern wells, cement is run all the way to the surface. The production casing is designed to withstand the maximum pressure of the treatment (i.e. hydraulic fracturing), or the maximum shut-in pressure of the well, whichever is greater. In many cases liners (tubular sections which are hung from previous casing sections and do not reach the surface. Once the production casing is set, well treatment operations, including perforating and hydraulic fracturing, can begin.²²

2. Well Stimulation

60. Well stimulation is the subject of the claims of the '394 Patent. Well stimulation is the treatment of the hydrocarbon formation itself, by mechanical or chemical means, in order to increase the speed of recovery of hydrocarbons from the well. Common well stimulation techniques that existed at the time of the '394 Patent,

²² Ex. 2008 at pp. 1-6.

include acidizing and hydraulic fracturing. Other lesser used techniques include nitrogen or carbon dioxide fracturing as well as “foam” fracturing.

a. Acidizing

61. Acidizing is the treatment of the formation with an acidic fluid. According to *Manrique*, “[t]he main purpose in any acidification treatment is the dissolution of minerals from the formation or precipitated solid material in the near wellbore areas.”²³ Some formations deposit minerals into the perforations or the formation face, causing blockage of the flow of hydrocarbons. Often these are calcium deposits, but silicate deposits are also known to cause blockage. In these cases acid treatments are used to dissolve the deposits and “clean up” the perforations or the face of the formation.

62. Other formations, such as limestones, react directly with acids. In these formations, the introduction of acid causes portions of the formation to break down, increasing the permeability of the formation. The depth of this increase permeability is a result of the strength of the acid and the pressure the acid is introduced with. Several acids are known to be used in acidizing, including hydrochloric acid (HCl), hydrofluoric acid (HF), citric acid, and acetic acid.²⁴ Each react differently with

²³ Ex. 2009 at 1.

²⁴ Ex. 2009 at Abstract.

different mineral deposits, as well as the hydrocarbons themselves and the downhole metallic structures (i.e. casing, tubing, etc.).

b. Hydraulic Fracturing

63. Fracturing the hydrocarbon bearing formations is a technique that has been used to increase or speed up oil and gas production for nearly as long as oil and gas production has existed. Fracturing methods as early as the 1850's used explosives such as gunpowder ignited by red-hot iron or nitroglycerin "torpedoes."²⁵ Hydraulic fracturing, in its modern form of pumping liquids and proppants (*e.g.*, sand) into the formation, began in the 1940s using a process developed by Stanolind Oil and used by Halliburton in the mid-continent region. Early hydraulic fracturing in the 1940s and 1950s used frac pumps, including pumps that could operate at around 1500 Hp.²⁶

²⁵ Ex. 2010 at 1.

²⁶ Ex. 2011 at p. 26.



First Hydraulic Fracturing Operation²⁷

64. The expansion of directional and horizontal drilling extended the use of hydraulic fracturing into previously underdeveloped “tight” formations, including shale. In oil and gas exploration, directional drilling is a technique for accessing hydrocarbon bearing formations (oil and gas formations) that are not located immediately beneath the surface location, or to increase the amount of formation exposed to the wellbore. Some tool or process is used to cause the wellbore to deviate from the vertical to reach previously inaccessible formation locations, to expose more of the hydrocarbon bearing formation to the wellbore, or to drill several wells from a single surface location, such as an offshore platform or a land-based drilling pad. Like most developments in the oil and gas industry the early drilling of

²⁷ Ex. 2011 Fig. 2.

directional wells was clearly motivated by economics. It was the offshore fields of California that spawned the technology which led to modern directional and horizontal drilling. In the 1930s, directional drilling was being used in the Huntington Beach, California field to reach an offshore oil-bearing formation from a well initiated on an onshore pad.

65. Because more formation is exposed to be fractured, horizontal wells use much higher volumes of fracturing fluid and proppant than do vertical wells. This requires the use of more and bigger blending and pumping systems. As discussed by *Grieser*, fracturing systems were growing in volume, particularly in exploration of previously unattractive formations such as Shales. *Grieser* describes that, by the 1970s to early 1980s, frac fluid volumes were around “1,200 gal/ft” of formation to be treated. By the late 1990s into the early 2000s, typical volumes in horizontal shale formations were 2,000 – 2,500 gal/ft with “pay sections” of around 400 ft, with pressure ranges around 6,000 PSI.²⁸ Other references, such as those from the North Sea, indicate available fracturing horsepower was in the “8,800 to 12,400 hhp” range, with bottom hole treating pressures of around 15,000 PSI.²⁹ While not reaching the volumes, treatment zone lengths or pump rates of massive hydraulic

²⁸ Ex. 2012 at p. 8.

²⁹ Ex. 2013 at p. 9.

fracturing operations which developed later in the 2000s, (such as those shown in Dr. Nikolaou's references), it was clear that the volume and rates of fracturing fluid handled, and the size of equipment necessary to do so, was increasing by the time of the '394 Patent.

66. The basics of fracture stimulation have not changed significantly since 1949 when Halliburton first commercialized the "hydrafrack" process. Hydraulic fracturing still involves pumping water (or another liquid, foam or gas) blended with a proppant (*e.g.*, sand) and other chemicals into the downhole reservoir at a sufficient pressure to crack (fracture) the downhole rock. The sand-water mixture is then forced into the cracks, where the sand keeps the cracks (fractures) open to allow hydrocarbons, such as oil and natural gas, to flow out of the formation into the well bore. What has changed over the years are the pressures, flowrates, and volumes of the fracturing jobs, the sizes of equipment (and related power demands), and the particular proppants, chemicals and liquids used.

67. At the time of the '394 Patent, a fracturing process required multiple pumps, operating together as a system to provide fracturing fluid with the right composition, at the right flowrate, and at a pressure sufficient to fracture the formation. At the beginning of the pumping chain are the water transfer pumps. These pumps operate at a relatively low pressure to move water from the storage location (*e.g.*, ponds, tanks) to the blender or the hydration unit.

68. In the blender, the water is mixed with a proppant, such as sand, or resin-coated sand or ceramics, to form the fracturing slurry. Additionally, other chemicals, such as acids, gels, friction reducers, biocides and the like, if used, may be added to the slurry on-site or added to the water off-site. Off-site addition reduces the number of tanks, pumps and pipelines at the fracturing site and reduces congestion. Dry products, such as sand, may be transported into the blender tub using conveyors or augers. Liquid products, such as chemicals, if used, may be transported into the blender tub using pumps of various sizes and types. These are typically relatively small horsepower pumps operating at lower pressures, as the blender tub operates at, more or less, ambient pressures.

69. Once the fracturing slurry is blended to the proper makeup and consistency, it is transferred to the fracturing pumps using a blender discharge pump. This discharge pump typically operates at a higher pressure than the water transfer pumps for several reasons. First, the viscosity of the slurry is typically higher than that of water, which requires higher pressures to move the same volume of slurry. Second, the slurry is heavier than plain water, requiring additional horsepower to move the slurry (as compared to plain water). The fracturing pumps then pump the slurry downhole at a pressure sufficient to mechanically fracture the target formation, which as discussed above was about 6,000 psi to 15,000 psi at the time of the '394 Patent. As shown in the image below, a hydraulic fracturing manifold,

commonly called a “missile” collects the discharge of the high pressure pumps and directs the comingled fluid to the wellhead.

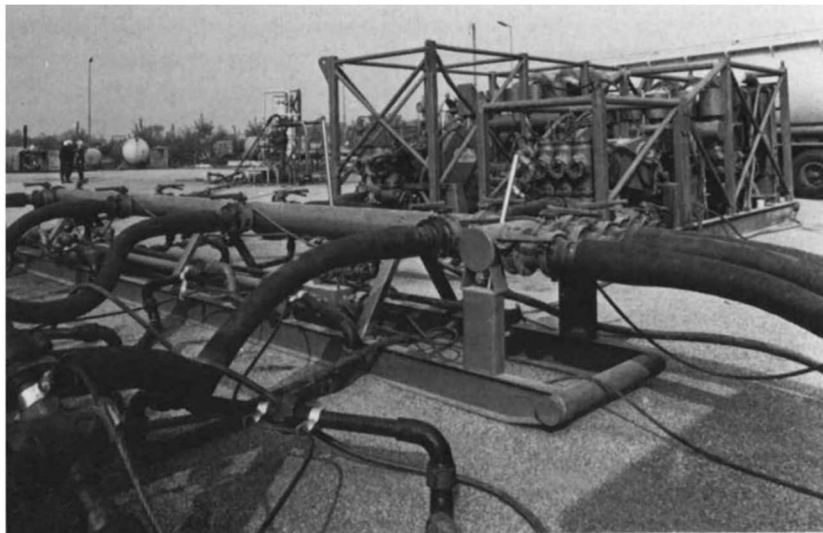


Figure 3.61 Close-up view of some of the large amount of equipment required at the well-site for an hydraulic fracturing job. (Photo: NAM).

Fracturing Equipment On-Site³⁰

3. Completion Equipment and Contractors

70. Completion equipment ranged from a simple wireline logging truck to the large, but portable, pumps, pipes and control equipment run for a large hydraulic fracturing operation. Logging operations, such as that shown in the figure below, include lowering a suite of equipment downhole which measures the properties of the formation such as permeability, porosity or presence of hydrocarbons. In a completed well, logging is used to determine the quality of the cementing job,

³⁰ Ex. 2007 at p. 115.

presence of joints in the casing or, the location of the perforations.³¹ The wireline rig is also used during fracturing operations, such as the “plug and perf” method of fracturing which dominated the industry at the time of the '394 Patent.

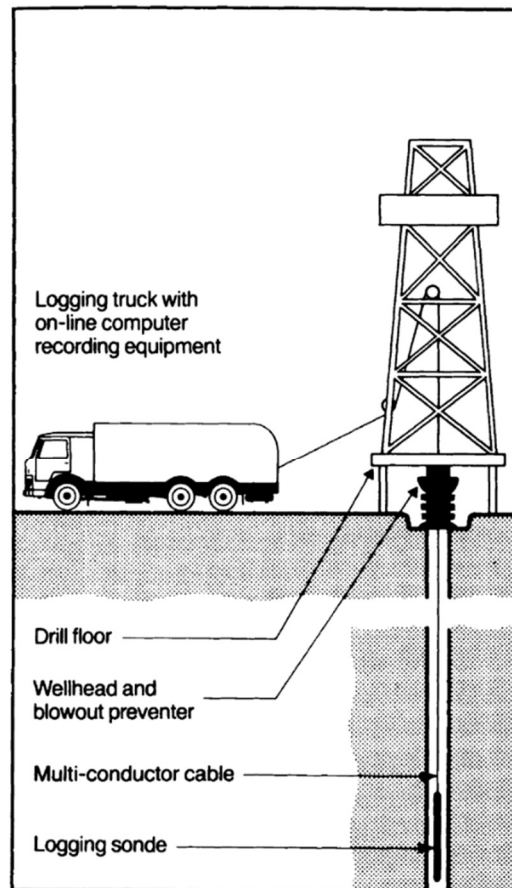


Figure 3.31 Wireline logging operations

Wireline Logging Operations³²

³¹ Ex. 2007 at 79.

³² Ex. 2007 at p. 79.

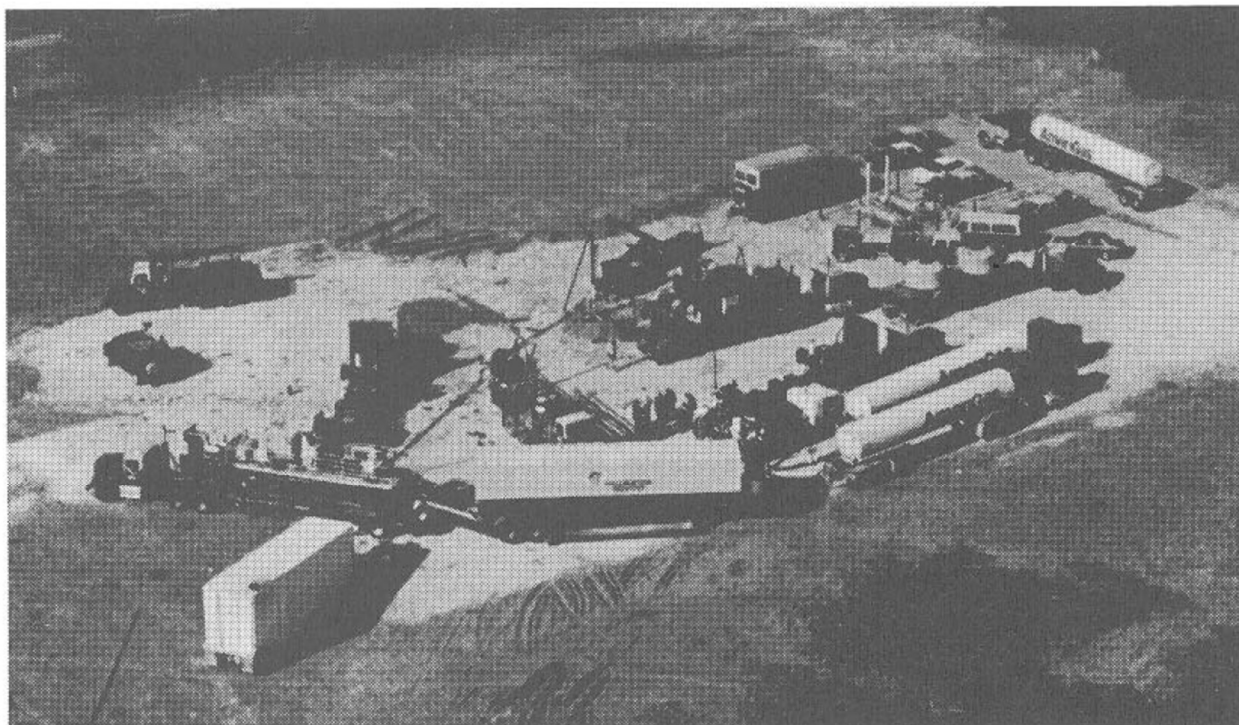
71. As discussed above, hydraulic fracturing involves the use of various types of pumps to pump proppant (e.g., sand) laden fluid down the wellbore in order to open fractures in the hydrocarbon bearing formation and allow hydrocarbons an easier path to flow into the wellbore. Figures showing such equipment are below. This equipment, though large, are also portable and move from site to site to stimulate different wells.³³



Closeup of Fracturing Equipment³⁴

³³ Ex. 2014 at p. 49.

³⁴ Ex. 2007 at p. 115.



Fracturing Spread³⁵

72. Contractors for some type of completion services, such as wireline, perforation and coil tubing operations, vary significantly from geographic region to geographic region as the equipment is relatively small compared to other operations (such as drilling or hydraulic fracturing). Some of the large contractors for fracturing operations at the time of the '394 Patent were Halliburton, Schlumberger, and BJ Services.

³⁵ Ex. 2014 at p. 49.

4. Flowback

73. Once the fracturing job is complete, fracturing fluid is recovered during a process known as “flowback.” As the fracturing fluid is introduced into the formation, it travels into the fractures (natural and man-made) and deposits the proppant into the fractures. As the fracturing fluid is injected at a higher pressure than the natural pressure (shut in pressure) of the formation, the fluid temporarily blocks the hydrocarbons from flowing into the well. During flowback, the fracturing fluids are allowed to “flow back” to the surface, where they are collected for treatment, recovery of skim hydrocarbons, and disposal. As the fluid leaves the formation, the proppant, ideally, stays in the formation and “props open” the fractures, increasing permeability of the formation. For large fracturing jobs, flowback is provided through a series of pressure reducing valves and collected into a series of portable tanks (frac tanks) by a specialized “flowback” contractor.

C. OIL AND GAS PRODUCTION

74. The goal of the exploration, drilling, completion and treatment process is to produce economically acceptable quantities of hydrocarbons (oil and gas) for collection and sale. After the well has been stimulated (fractured), the fracturing equipment is moved to the next location to be fractured. The well is then turned over to production and production equipment, such as production tubing, downhole pumps, permanent collection tanks, etc. are brought in and installed at the site.

Production tubing is run inside the casing to create a conduit for production fluids to flow from the bottom of the well to the wellhead located at the surface. As discussed below, production fluids contain three phases – solids (e.g., sand) from the formation, liquids (e.g., hydrocarbons (oil) and saltwater), and gaseous natural gas.³⁶ Oil and gas production from a well at the time of the '394 Patent commonly lasted more than ten years, sometimes up to 30 years, with proper maintenance.

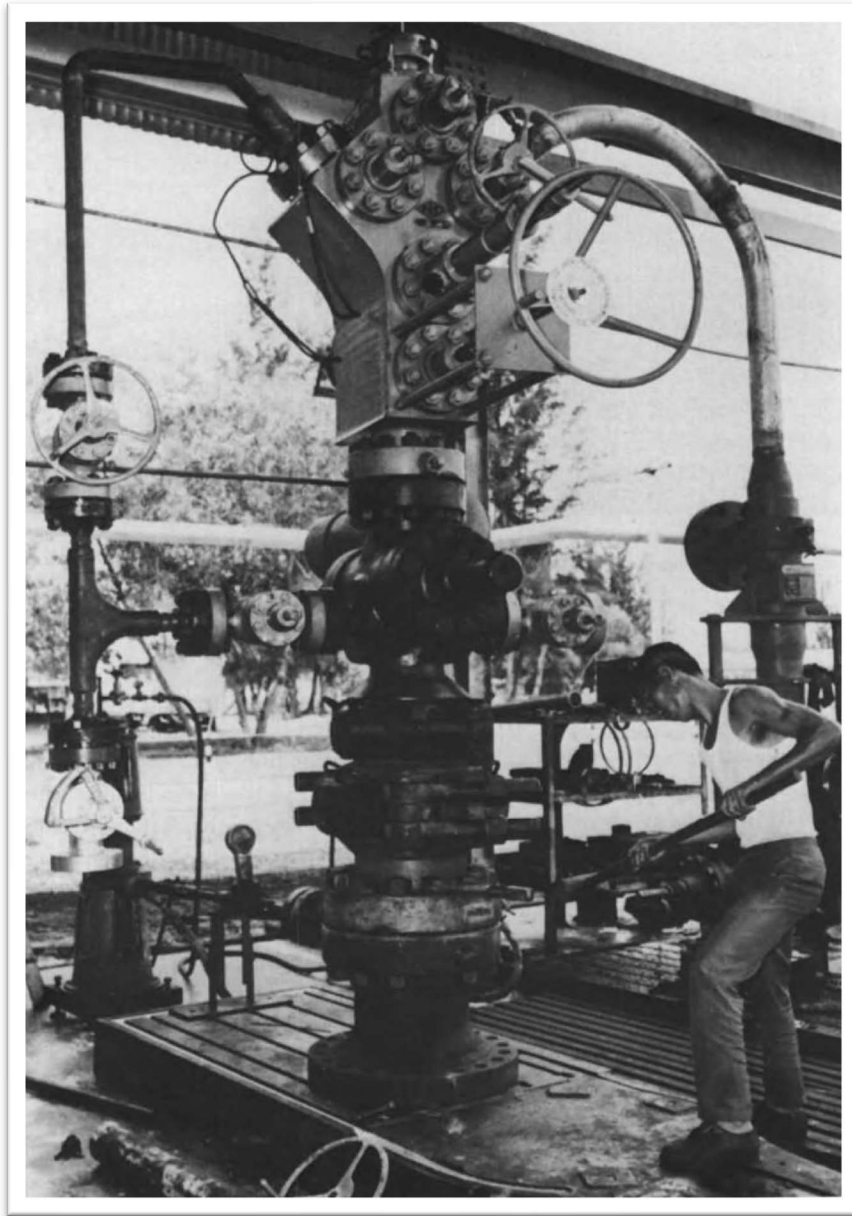
1. Collection Equipment

75. In a new field, wells are often overpressured, with enough bottomhole pressure to overcome the fluid head of the well. As a result, oil and gas (and often water) flow to the surface without any additional assistance. In such locations, oil flowed to tanks and gas flowed to a pipeline (if present) for sale or to a flare, if a gas gathering system was not available.³⁷ These wells were controlled by “Christmas Trees” located at the wellhead that contain a series of valves used for shut-in and pressure control. A picture of a Christmas Tree is shown below. In overpressured fields, the only power consumption are very small (~10 hp) transfer pumps or chemical injection pumps. In locations where there are multiple wells flowing into a single storage or treatment facility, collection manifolds are used to comingle the

³⁶ Natural gas is composed of methane, along with other gaseous hydrocarbons, along with varying amounts of other gases such as helium and hydrogen.

³⁷ Ex. 2007 at p. 115.

production fluids into a single pipeline for delivery to the storage or treatment location.³⁸



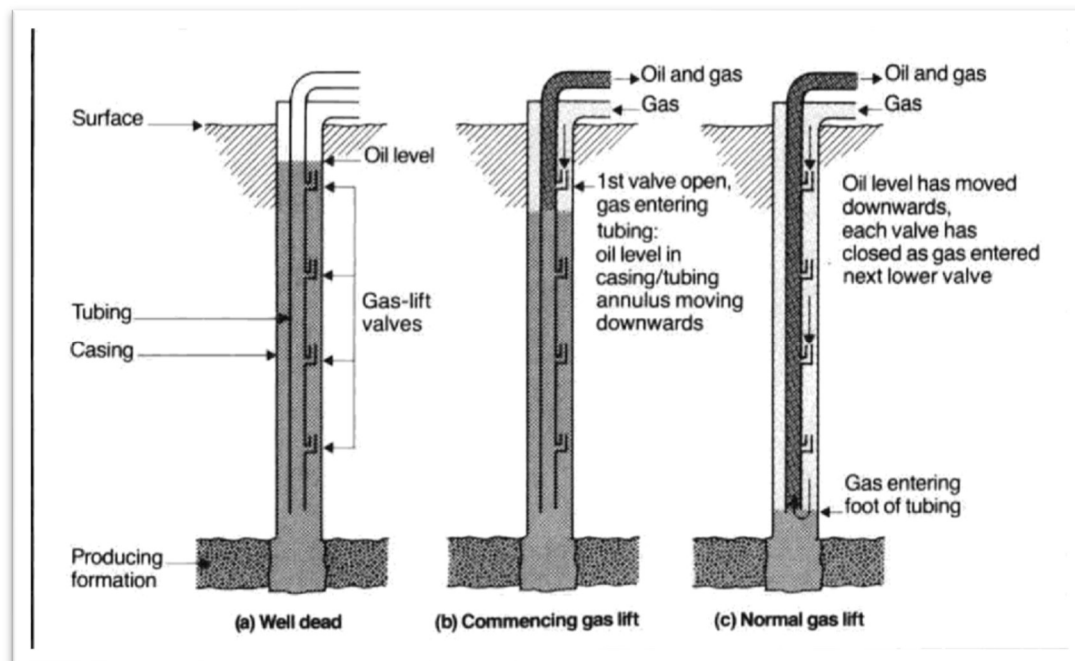
Off-shore Christmas Tree³⁹

³⁸ See, e.g., Ex. 2022 at p. 2.

³⁹ Ex. 2007 at p. 116.

76. In fields where wells are underpressured (i.e., not enough bottomhole pressure to raise liquids to the surface), some type of artificial lift operation was used to produce the hydrocarbon liquids in commercially viable quantities. Such artificial lift technologies included gas lift, ball and valve pumping and electrical submersible pumping. Gas lift involves injecting quantities of gas (which at the time had significantly less value than the hydrocarbon liquids) back into the well in order to increase pressure in the annulus (i.e., the space between the production tubing and the casing) and force oil into the tubing. This technology involved natural gas driven compressors to increase the pressure of the gas and a series of sequenced opening valves in the production string. Power consumption ranged from tens of hp per well and was provided by a portion of the produced gas. Other power consumptions are transfer pumps and chemical pumps as with overpressured fields. The figure below shows basic gas lift valve operation.⁴⁰

⁴⁰ See, e.g., Ex. 2007 at pp. 115-119.

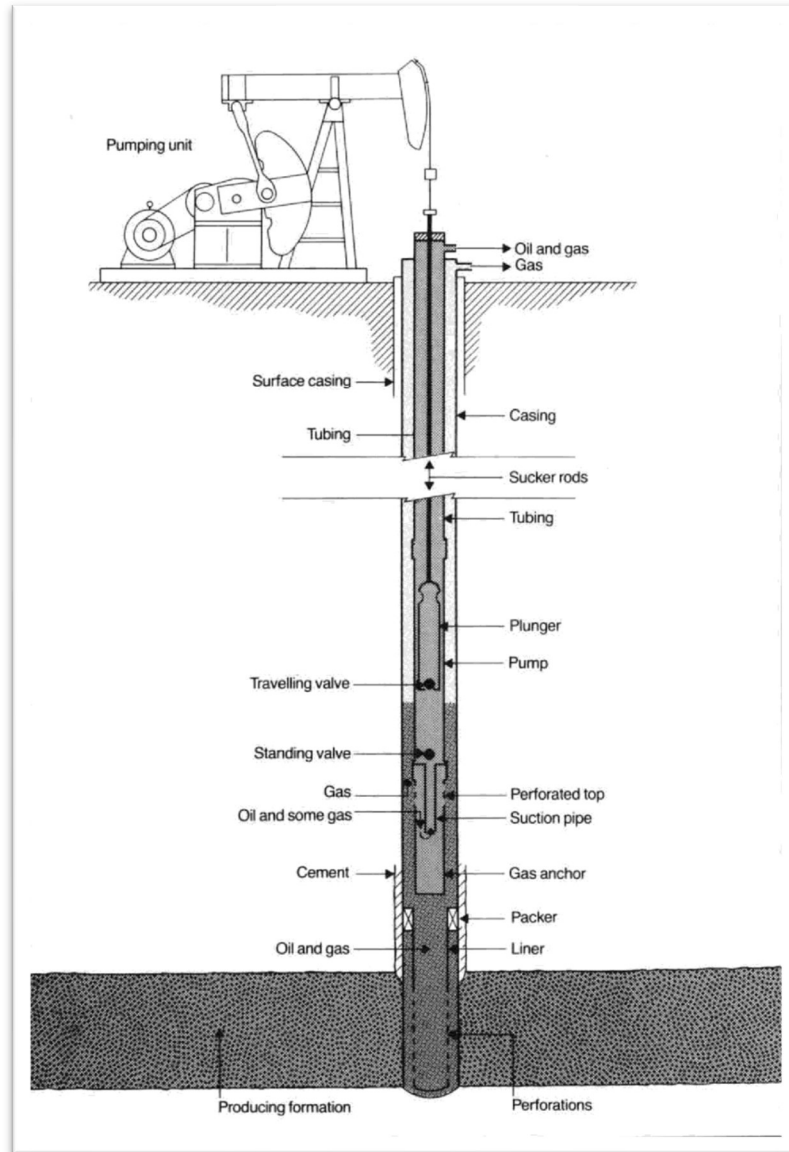


Gas Lift Valve Operation⁴¹

77. As shown in the figure below, ball and valve pumping involved a downhole pump with two sets of balls and valves, standing valve and traveling valve. The pump operated vertically. As the pump was separated (e.g. traveling valve moving upward), the standing valve would open allowing hydrocarbons to flow into the barrel of the pump. As the pump was closed (e.g., traveling valve moving downward), the travelling valve would open and hydrocarbon fluids would move upward into the production tubing. The movement of the pump was controlled by a surface pumping unit, often the ubiquitous “pump jack” visually associated with oil and gas fields. A picture of pump jacks in operation is shown below. These pumping

⁴¹ Ex. 2007 at p. 118.

units were run by small (tens of Hp) electric motors or natural gas engines, along with the transfer and chemical pumps mentioned above.⁴²



Ball and Valve Pumping Installation⁴³

⁴² Ex. 2007 at pp. 119-122.

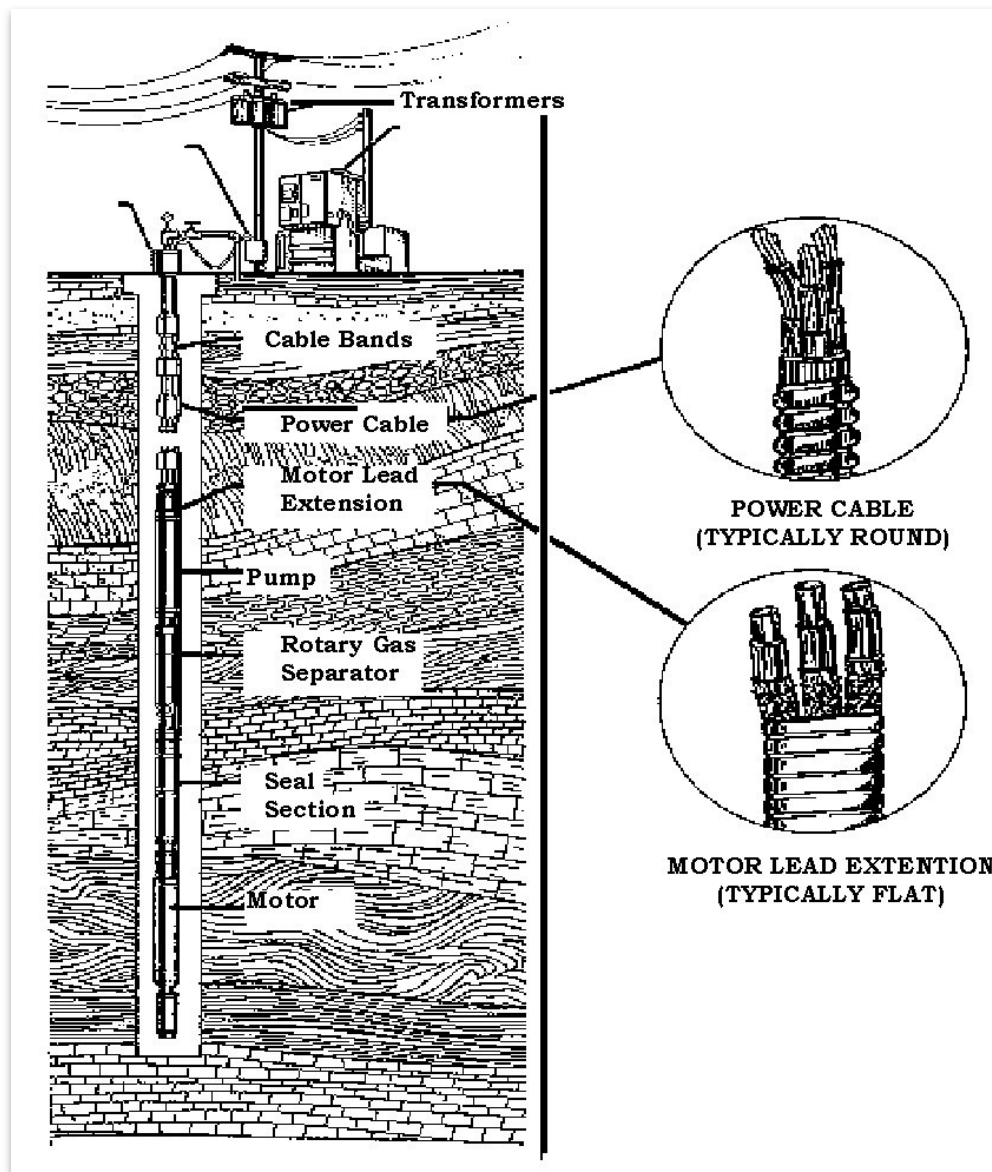
⁴³ Ex. 2007 at p. 120.



Pump Jacks in Operation⁴⁴

78. The third primary technology used for artificial lift (e.g. pumping) recovery operations were electric submersible pumps (“ESP”). An ESP is simply a centrifugal pump comprised of multiple centrifugal impellers which are small enough to fit into the wellbore. ESPs were often ~4.5” in diameter and 20-30 feet long. ESPs often operated at medium voltage (~2.3kv – 5kV) and typically consumed a couple of hundred Hp per well. ESP installations required much more extensive electric service equipment.

⁴⁴ Ex. 2007 at p. 121.



ESP Installation⁴⁵

2. Separation and Storage Facilities

79. Economic production from oil (and natural gas) wells requires the flow of significant volumes of fluid from the hydrocarbon bearing formation into the

⁴⁵ Ex. 2016 at p. 3.

wells, to the surface, and then to storage tanks. The fluid from oil wells is typically a three-phase fluid comprising liquid (oil and salt water), gas (methane and other gases) and solids (sand and rock remnants). At the wellhead, these components are part of a single flow stream. In order for sale of the commercially valuable components (oil and hydrocarbon gases), the three phases are initially separated in a three-phase separator. A three-phase separator is a vessel that “slows down” the production stream (often in a pressurized vessel) and allows for settling of the solids to the bottom of the separator (where they are collected and discarded) as well as allowing the gaseous products to “break out” of the liquid stream. The gas is then collected, often compressed, and delivered to a natural gas pipeline for sale or, in cases where no pipeline is available, burned off in a controlled manner using a flare system.

80. The liquid stream, comprised primarily of salt water and oil (along with treating chemicals and other trace minerals), is then delivered to a processing facility, typically on site or near the wellhead, where the oil and salt water are separated by another settling process, sometimes accelerated by heat. As oil has a lower density than salt water, most of the oil “floats” to the surface of a settling tank (heater treater, gun barrel, free water knockout or other names). The oil is collected and delivered to storage tanks or a pipeline for sale and the saltwater (i.e., produced water) is directed to storage tanks or a pipeline for eventual disposal. In many wells,

the volume of produced water is ten times or greater than the volume of produced oil.⁴⁶

3. Production Chemicals

81. In order to aid the flow of hydrocarbons through the production tubing and through the gathering system, certain “production chemicals” are often used.

These consist of two basic types:

- a. Chemicals to prevent the formation of “plugs” in the lines, such as wax and paraffin inhibitors and natural gas hydrate inhibitors.⁴⁷
- b. Chemicals to prevent corrosion to the steel lines and tanks (corrosion inhibitors).

These chemicals are used in very small volumes and flowrates when compared to production fluids or stimulation fluids. Wax and paraffin inhibitors are usually used in the rate of ounces per barrel of oil, hydrate inhibitors are used in the range of gallons per barrel⁴⁸ of water, and corrosion inhibitors are typically used in the range of 0.25 lb / hr (4 oz / hr).⁴⁹ This is compared with the fracturing flowrates discussed

⁴⁶ Ex. 2021 at pp. 206-209.

⁴⁷ Paraffin is a term of art used to describe the thick, highly viscous, waxes, asphaltenes and other hydrocarbons that, at ambient conditions, could congeal in production lines. Natural gas hydrates contain a small amount of hydrogen contained within a solid crystal formation of water.

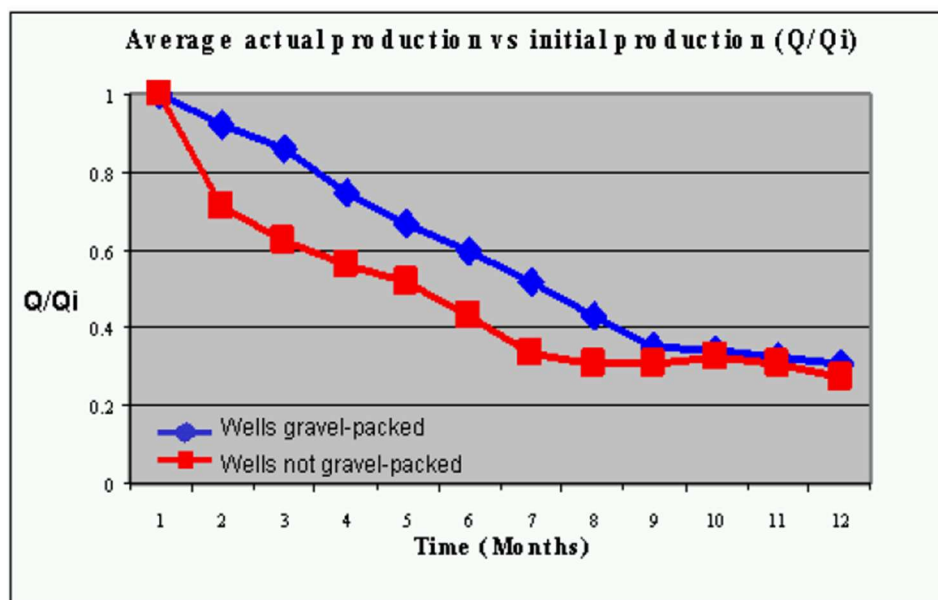
⁴⁸ Ex. 2017 at 1.

⁴⁹ Ex. 2018 at 5.

above in the tens to hundreds of barrels per minute (bbl/min), or production flowrates of barrels per day (bbl/day). Injection pressures of these chemicals are just enough to overcome the pressure in the gathering system pipelines and production tubing, typically hundreds of pounds per square inch (PSI).

4. Well Maintenance

82. After the well has been producing for a period of time, the production of hydrocarbons tends to progressively get lower and lower. The shape of production over time is called the “production curve” and a typical production curve shows a decline in production over time. This is due to a number of factors. Typical declining production curves comparing gravel pack and non-gravel pack wells are shown below:⁵⁰



⁵⁰ Ex. 2019 at 12.

83. The most important factor in the decline of hydrocarbon production is the loss of bottom hole pressure due to the extraction of the hydrocarbon (and water) components of the well fluid. In originally overpressure fields, secondary and tertiary lift mechanisms (e.g., electric submersible pumps, gas lift, beam pumps, steam injection) can be added to the well to assist with lifting the fluid to the surface. Other factors include pack-off of the formation face (or perforations) such as with paraffin or scale, plugs developing in the production tubing or casing, mechanical damage to the well, or formation damage near the wellbore due to high-flow production, flowback or the completion process itself. Maintenance activities intended to deal with such problems are referred to as well intervention.

84. Well intervention can be as simple as injecting an acid or other solvent into the wellbore annulus (between the tubing and the casing) in order to “break up” plugged perforations or to clean the tubing. For more extensive problems, such as a plugged tubing or casing, the production tubing will be removed and cleaned, and mechanical cleaning tools, such as a paraffin knife, are used to “scrape out” the casing. Another class of intervention involves repairing problems with casing, tubing, or downhole tools, referred to as “integrity repairs.” These also typically involve removing the production tubing.

85. Another category of well intervention are optimization techniques, aimed to increase the production levels, or to flatten the production curve. These

interventions are completed “by stimulations and additional perforation (infill or new zone), change a well status to improve vertical lift.”⁵¹ The most common stimulation treatments are injection of acids to either clean the tubing or to “etch” the facing of the formation to reduce damage or open plugged formation face or perfs.⁵² According to Chike, “[c]onventional acid systems including the numerous patented HF – HCl and organic acid blends dissolve the plugging solids and cementitious materials.”⁵³ These acids, and other chemicals, stimulate production of the well by removing blockage in the formation, and in some cases create new etched channels in the formation for increased permeability of the near-well formation. Further, “[s]olvents and solvent / surfactant /dispersant trains are excellent means of organic damage removal in the reservoir.”⁵⁴ Relatively large quantities of acid (as compared to production fluids) are used, typically 50 – 100 bbl of fluid.⁵⁵ However, this is still very small volumes of fluid as compared to the thousands of barrels of fracturing fluid typically used in horizontal wells (which were common in 2005).

⁵¹ Ex. 2020 at p. 6.

⁵² Ex. 2020 at p. 6.

⁵³ Ex. 2020 at p. 1.

⁵⁴ Ex. 2020 at p. 1.

⁵⁵ Ex. 2020 at pp. 6-7.

86. Another well intervention technique is to fracture stimulate the formation. Although the majority of large fracturing jobs are performed in low permeability formations at the beginning of the well life (during the completion phase), fracture stimulation is also used to re-invigorate old or underperforming wells. According to Moore, “[t]he objective of any fracture stimulation treatment either during initial completion or during restimulation is to definitely bypass the near-wellbore damage, penetrate deeper into the reservoir and increase connectivity with the reservoir.”⁵⁶ The steps of fracture stimulation as a well intervention technique are the same as those described above.

87. The most intrusive well intervention technique is re-completion of the well. Re-completion involves activities including adding new perforations (new zone or increasing perforations in the zone, squeezing off (cement blocking) non-producing or water-producing perforations or zone, or performing additional hydraulic fracturing stimulation treatments to create more channels for hydrocarbon flow.

⁵⁶ Ex. 2015 at p. 1.

X. OVERVIEW OF THE PRIOR ART

A. CROSSLEY (EX. 1005)

88. International Patent Publication WO2005/111369 to Crossley et al. is entitled “System and Vessel for Supporting Offshore Fields.” *Crossley* was filed on February 23, 2005 and published on November 24, 2005.

89. *Crossley* “generally relate[s] to a system for supporting a plurality of hydro-carbon-bearing wells, including systems for providing production operations in multiple-well-site, offshore fields.”⁵⁷ Each well-site has one or more wells.⁵⁸ For example, in Figure 1 below, “the three fields 10, 20, 30 are being produced through three separate subsea well-sites” 110, 120, 130, and each well-site “has a plurality of wells 112, 122, 132 clustered together.”⁵⁹

90. *Crossley*’s system “comprises a floating vessel [150] that is relocatable from a first subsea well-site to a second subsea well-site.”⁶⁰ “The system also comprises two separate systems: (1) an operations control system for providing subsea well-site operations such as power and communications” (annotated in blue

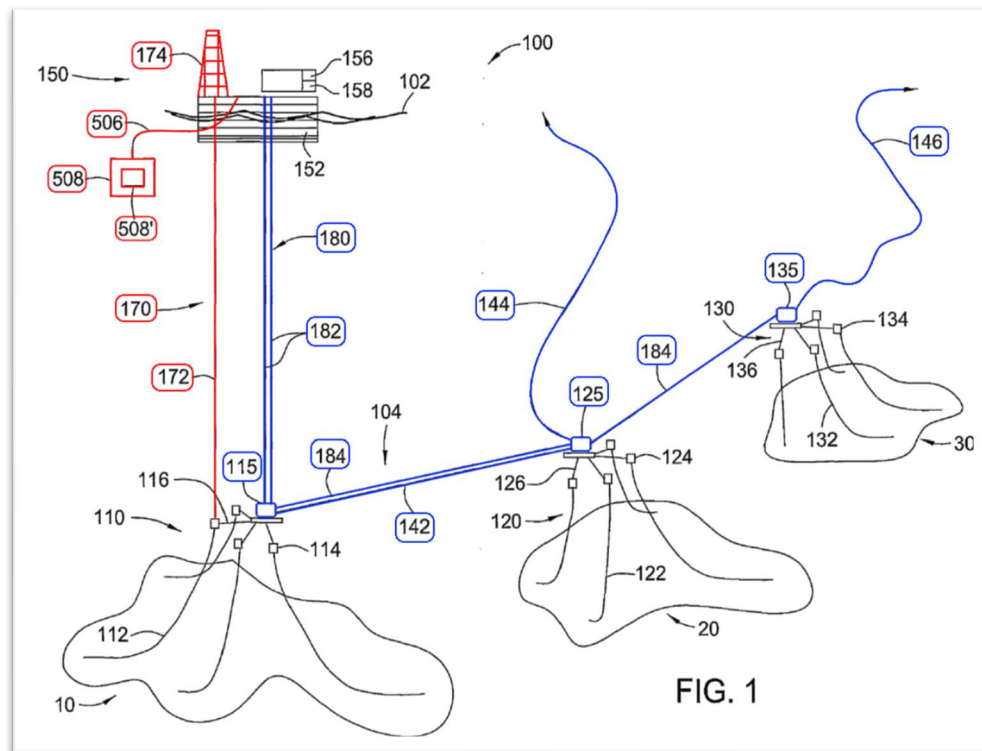
⁵⁷ Ex. 1005 at [0002].

⁵⁸ Ex. 1005 at [0008].

⁵⁹ Ex. 1005 at [0043].

⁶⁰ Ex. 1005 at Abstract, [0008], [0018].

in Figure 1 below), “and (2) an intervention system for conducting intervention services to an individual subsea well such as workover services and maintenance services” (annotated in red in Figure 1 below).⁶¹



91. *Crossley's* operations control system (blue) “is connectible to the floating vessel for simultaneously providing subsea well-site control operations at the first and second offshore well-sites” from either well-site location.⁶² *Crossley* discloses that control operations “include communications for at least one of commands sent to well-site equipment, and data received from sensors in the well-

⁶² Ex. 1005 at [0009], [0019].

site equipment.”⁶³ *Crossley* also discloses that “[t]he control operations may further include the delivery of chemicals to selected flowlines, the de-liver of hydraulic fluid to selected subsea equipment, the delivery of low voltage electrical power for control equipment, and the delivery of electrical power for high power production equipment.”⁶⁴

92. Specifically with respect to Figure 1, *Crossley* discloses that “[t]he operations control system 180 preferably employs two control links”—first, “a surface vessel control link 182 that extends from the relocatable vessel 150, downward to one of the collection manifolds, e.g., manifold 115,” and second, “an inter well-site controls network 184 that connects the subsea well-sites 110, 120, 130 together.”⁶⁵ With respect to “the delivery of chemicals to selected flowlines,” *Crossley* teaches that “[c]ontrol operations may further include the injection of chemicals such as hydrate, paraffin, or wax inhibitors into flow lines.”⁶⁶ *Crossley* refers to such chemicals as “production chemicals.”⁶⁷ Figure 4 of *Crossley* provides

⁶³ Ex. 1005 at [0019].

⁶⁴ Ex. 1005 at [0019].

⁶⁵ Ex. 1005 at [0049].

⁶⁶ Ex. 1005 at [0048].

⁶⁷ Ex. 1005 at [0009].

“an illustrative integrated line as may be used to transmit control features for the system.”⁶⁸ “Lines 428 and 428’ are preserved for the delivery of chemicals, such as hydrate inhibition fluids.”⁶⁹ “Chemicals may be delivered from the lines 428, 428’ and then through the manifold 115 for treatment of flow lines, valves, and even the wellbores as appropriate.”⁷⁰

93. Unlike *Crossley’s* operations control system that simultaneously provides control operations to two separate wells or well-sites, *Crossley’s* intervention system (red) is “for conducting intervention services to an individual well.”⁷¹ As shown in Figure 1, “the well intervention system 170 operates through the use of a workover riser 172 and an ROV system 508.”⁷² “The riser 172 extends from the relocatable vessel 150, downward through the ocean to the wellhead of an individual well.”⁷³ “[T]he riser 172 may be disconnected from the wellhead of well

⁶⁸ Ex. 1005 at [0015].

⁶⁹ Ex. 1005 at [0050].

⁷⁰ Ex. 1005 at [0050].

⁷¹ Ex. 1005 at [0020]; see also Ex. 1005 at Abstract, [0010], [0025], [0026], [0030], [0037], [0038], [0056], [0061], Cl. 1 (disclosing intervention services for only one “an individual well” at a time).

⁷² Ex. 1005 at [0054].

⁷³ Ex. 1005 at [0056].

112, and reconnected to the wellhead of any other well in that subsea well-site 110,” or “[a]lternatively, the vessel 150 may be relocated to a second subsea well-site, e.g., site 120, where the workover riser 172 may be connected to a production or injection well in that second well-site, e.g., well 122.”⁷⁴

94. “The intervention services include at least one of workover services and maintenance services.”⁷⁵ As used in *Crossley*, “‘workover’ refers to both major and minor well interventions.”⁷⁶ “Major interventions are those that require the pulling of tubing from the well” where as “[m]inor interventions, on the other hand, do not require the pulling of tubing.”⁷⁷ One example of a minor intervention provided in *Crossley* is “the injection of acid or other treating fluids.”⁷⁸ As used in *Crossley*, “‘[m]aintenance’ refers to the maintaining of equipment at the mudline or the wellhead platform, including equipment associated with the wellhead, the collection manifold, and any subsea fluid separators.”⁷⁹

⁷⁴ Ex. 1005 at [0056].

⁷⁵ Ex. 1005 at [0010].

⁷⁶ Ex. 1005 at [0037].

⁷⁷ Ex. 1005 at [0037].

⁷⁸ Ex. 1005 at [0037].

⁷⁹ Ex. 1005 at [0037].

B. ALBERS (EX. 1006)

95. U.S. Patent No. 7,451,820 to Albers et al. is entitled “Method For Fracture Stimulating Well Bores.” *Albers* was filed on April 29, 2005 and issued on November 18, 2008.

96. *Albers* is directed to “a method for fracture stimulating well bores using gaseous nitrogen and/or liquid carbon dioxide combined with substantially dehydrated proppant.”⁸⁰ As shown in Figure 1, *Albers* discloses “conventional” equipment used to manufacture and pump a fracturing fluid into a wellbore, including “[a] conventional blender unit (1),” “[a] conventional sand trailer (4),” “a conventional high-pressure pump (5),” “a conventional sand intensifier unit (7),” and “[a] first nitrogen/carbon dioxide storage tank and pump (10).”⁸¹ This equipment is attached to “a manifold connection ... which is in turn connected to a first wellhead conduit (13) that extends directly to the wellhead.”⁸² “A second nitrogen/carbon dioxide storage tank and pump (14) is shown extending directly to

⁸⁰ Ex. 1006 at 1:65-67.

⁸¹ Ex. 1006 at 3:56-4:4.

⁸² Ex. 1006 at 4:8-11.

the wellhead via a second wellhead conduit (13a), bypassing the sand intensifier unit (7) altogether.”⁸³

97. This conventional equipment in *Albers* is used to combine partially dehydrated or “wet” proppant with nitrogen/carbon dioxide and deliver it to a wellhead at a rate and pressure sufficient to fracture stimulate the formation.⁸⁴ *Albers* discloses two alternative procedures for delivering the wet proppant to a single wellhead overtime: (1) a “step” procedure and (2) a “ramp” procedure.⁸⁵ In the “step” procedure, “a measured of amount of proppant is introduced into the formation, followed by an increased amount, followed by a further increased amount, and so on until the proper prop-pant concentration is attained.”⁸⁶ In the “ramp” procedure, “an initially small, but steadily and constantly increasing amount of proppant is introduced into the formation until the proper concentration is attained.”⁸⁷

⁸³ Ex. 1006 at 4:11-14.

⁸⁴ See, e.g., Ex. 1006 at 2:25-27, 2:58-67, Cl. 1.

⁸⁵ Ex. 1006 at 6:50-7:25.

⁸⁶ Ex. 1006 at 6:52-56, FIGS. 5-6.

⁸⁷ Ex. 1006 at 7:3-7, FIGS. 7-8.

C. LEHMAN (EX. 1009)

98. U.S. Patent Pub. No. 2004/0050550 to Lehman et al. is entitled “Re-use Re-covered Treating Fluid.” *Lehman* was filed on September 16, 2002 and published on March 18, 2004.

99. *Lehman* is directed to “treating fluid production and subterranean formation treatment methods as well as compositions for treating fluids, all of which relate to re-use of at least part of a prior treating fluid.”⁸⁸ One method includes “treating a subterranean formation intersected by a well, comprising performing a treatment on a well using a treating fluid residual recovered from a prior treatment, wherein using a treating fluid residual recovered from a prior treatment includes conditioning the recovered treating fluid residual.”⁸⁹

XI. GROUND 1: CROSSLEY IN VIEW OF ALBERS DOES NOT RENDER THE CLAIMS OF THE '394 PATENT OBVIOUS.

100. After review of the evidence submitted in support of the Petition, including the prior art relied on and the declaration of Dr. Nikolaou, it is my opinion that the combination of *Crossley* and *Albers* does not render the claims of the '394 Patent obvious. A POSITA would not have been motivated to combine the teachings of *Crossley* with *Albers* with a reasonable expectation of success as they are directed

⁸⁸ Ex. 1009 at [0018].

⁸⁹ Ex. 1009 at [0020].

to different oil and gas operations and designed with different purposes in mind. Further, *Crossley* teaches away from the combination of equipment that the Petition and Dr. Nikolaou describe and rely on. Finally, there are claim elements missing from the combination of *Crossley* and *Albers* that Dr. Nikolaou does not show are obvious in light of the combination.

A. THE PETITION DOES NOT ESTABLISH A MOTIVATION TO COMBINE CROSSLEY AND ALBERS

101. A POSITA would not have been motivated to combine the teachings of *Crossley* and *Albers*. Initially, despite the Petition and Dr. Nikolaou's assertion that both *Crossley* and *Albers* are pertinent to "the need to efficiently conduct drilling operations," neither reference relates to drilling operations.

102. *Crossley* is not at all concerned with drilling operations or pre-production well stimulation but, instead, production operations. As described above in Section IX.C, production operations take place after all drilling, completion and stimulation operations have taken place and the equipment for each of those operations has been removed. The pumps and prime movers (i.e., motors, engines, etc.) used in production operations are much smaller in size than those used in well stimulation operations (i.e., tens to hundreds of horsepower vs. thousands for fracture stimulation operations).

103. Dr. Nikolaou's reference to *Crossley's* discussion of "drilling and maintenance of deep and remote offshore wells"⁹⁰ is not evidence that *Crossley* is directed toward drilling operations. This paragraph contains the only mention of drilling in all of *Crossley*. There are no references in *Crossley* to pre-production fracture stimulation of the well, the process to which *Albers* is directed. In examining the entire paragraph that Dr. Nikolaou referenced, it becomes clear that *Crossley* is not at all concerned about drilling operations, but about production operations, including the control of produced fluids.⁹¹

[0005] The drilling and maintenance of deep and remote offshore wells is expensive. In an effort to reduce drilling and maintenance expenses, remote offshore wells are oftentimes drilled in clusters. This allows a single floating rig or semi-submersible vessel to conduct drilling operations from essentially a single ocean location. Further, this facilitates the gathering of production fluids into a local production manifold after completion. Fluids from the clustered wells are oftentimes commingled at the manifold, and delivered together through a single flow-line. The flow line leading from the production manifold is sometimes referred to as a production export line. The clustering of wells also allows for one or more control lines to be run from a single location at the ocean surface, downward to the clustered wells. The control line ties into a control module on the manifold, and then branch to the various wellheads. Such a control line allows for the monitoring and control of valves, gauges, and other subsea equipment. Control lines also allow for one or more power lines or chemical delivery lines to be delivered from the ocean surface, downward to the clustered wells.

⁹⁰ Ex 1005 at [0005].

⁹¹ Ex 1005 at [0005].

104. Similarly, *Albers* is not directed toward drilling operations or production operations. *Albers* makes one reference that wells are drilled, with no other reference to drilling anywhere in *Albers*. A close reading of the paragraph that Dr. Nikolaou quotes shows that *Albers* is not at all concerned about drilling operations or production operations but is instead concerned with hydraulic fracturing stimulation.⁹²

Various methods are known in the prior art for stimulating the production of oil and natural gas from wells drilled in formations with low permeability. One of the most widely used methods involves the hydraulic fracturing of low permeability formations using one of a variety of water-containing fracturing fluids intermixed with proppants such as sand, glass beads, and the like. Hydraulic pressure is applied to the formation and causes stresses in the rock of the formation surrounding the well bore. These stresses trigger the splitting or “fracturing” of the rock. The initially formed fractures are then extended by the injection of fluids containing a proppant into the fractures. The hydraulic pressure is then released and the proppant which had been previously deposited in the fractures serves to hold the fractures open such that channels are created for reservoir fluids to flow to the well bore and subsequently to the surface.

105. Similarly, the '394 Patent is not at all concerned with drilling operations. As Dr. Nikolaou quotes, the '394 Patent is concerned with “the complex logistics that arise in the servicing and stimulation of wells which can require a series of coordinated operations that begin with the supply by truck of equipment, supplies,

⁹² Ex. 1006 at 1:6-21.

fuel and chemicals to the wellhead.”⁹³ The ’394 Patent is describing well service and stimulation, not “efficiently conducting drilling operations”.

106. Secondly, Dr. Nikolaou’s statement that all three references are directed to “oil well operations” is an overgeneralization. As discussed above in Section IX, there are distinct phases of “oil well operations,” each with its own concerns, equipment and service providers. Dr. Nikolaou provides no rationale why the teachings of a production operation, such as *Crossley*’s operations control system 180, which is used with production equipment would be pertinent to the focus of *Albers*, which is fracturing low permeability formations before production begins, or vice versa.

107. As Dr. Nikolaou quotes, but fails to recognize, *Crossley*’s operations control system 180 is associated with collection manifolds and systems on producing wells.⁹⁴ Dr. Nikolaou states that *Crossley*’s operations control system 180 “controls the configuration of manifolds 115, 125, and 135,” but then goes on to erroneously assert that these manifolds “direct fluid to selected wells.”⁹⁵ This is contrary to the teaching of *Crossley*, which teaches that manifolds 115, 125 and 135 are *collection*

⁹³ Ex. 1003 at p. 30, internal citations omitted.

⁹⁴ See, e.g., Ex. 1003 at ¶ 51.

⁹⁵ Ex. 1003 at ¶ 51.

manifolds, for collecting production fluids from the wells and directing them to a gathering facility. As *Crossley* teaches⁹⁶

As noted, each well-site 110, 120, 130 has a plurality of wells 112, 122, 132 clustered together. Each well 112, 122, 132 has a flow line jumper 116, 126, 136 extending from the trees 114, 124, 134 in order to transport production or injection fluids. The flow line jumpers 116, 126, 136 in each respective well site 110, 120, 130 tie into a collection manifold 115, 125, 135. In this way, production fluids from a well-site can be commingled for unitary transportation to another location (such as a gathering facility seen at 190 in Figure 5).

There is a single reference to the manifolds being used to introduce “chemicals” into the manifold “for treatment of flow lines, valves, and even the wellbore as appropriate.” However, in context, this paragraph is clearly dealing with production chemicals (such as hydrate inhibitors), and not “well stimulation fluids.” As discussed below in greater detail, *Crossley* actually teaches against the introduction of “well stimulation fluids,” such as acid, into the manifolds 115, 125, 135, by instead teaching a separate, one well at a time “well intervention system 170” for injection of well stimulation fluids to the wells.

108. Accordingly, there is no relationship between “manifolds 115, 125, 135” and delivery of well stimulation fluids *to* a wellbore, as discussed in *Albers* and the claims. The manifolds are used to collect fluid *from* the wellbore, and to introduce relatively small quantities of production chemicals as a preventative to

⁹⁶ Ex. 1005 at [0045].

plugged or corroded lines, including, perhaps, well tubing/casing. Due to the presence of flowing hydrocarbons from the formation, into the well bore, and then up the tubing to the well head, it would not be possible to simultaneously inject well stimulation fluids to the formation and produce at the same time. Accordingly, the chemicals taught to be injected into the manifolds are production chemicals, not well stimulation fluids.

109. Further, Dr. Nikolaou erroneously relies on *Crossley's* teaching of the control system providing “hydraulics, electric power and/or chemical distribution” to somehow suggesting that the equipment of *Albers* would be incorporated into *Crossley's* control system 180. However, Dr. Nikolaou ignores and leaves out the teaching of *Crossley* in the same paragraphs that Dr. Nikolaou quotes that the “chemicals” distributed by the control system are not at all stimulation fluids, but instead are production chemicals. *Crossley* teaches, quoting the entire sentence, “[c]ontrol operations may further include the injection of chemicals such as hydrate, paraffin, or wax inhibitors into flow lines.”⁹⁷ A POSITA would recognize that chemicals such as those described in *Crossley* are used in very small quantities (quarts to barrels per day), and not the relatively large quantities employed for the

⁹⁷ Ex. 1005 at [0048].

stimulation fluids of *Albers* (barrels per minute).⁹⁸ Accordingly, a POSITA would not look to the teachings of *Crossley's* control system 180, designed to deliver small quantities of production fluids to understand how to deliver the large quantities of stimulation fluids of *Albers*.

110. The Petition and Dr. Nikolaou do not provide any reasons why a POSITA would have been motivated to combine *Crossley's* production system and *Albers's* fracture-stimulation equipment. The benefit disclosed in *Albers* of manipulating the composition of a fracture-stimulation fluid on the fly relates only to fracture-stimulation operations and does not relate to production operations. In fact, *Albers* does not disclose any benefits applicable to ongoing production operations to which *Crossley* relates.

111. The Petition and Dr. Nikolaou rely on *Albers*, *Lacy*, and *Tolman* to support the combination of *Albers's* fracture-stimulation equipment with a *Crossley's* production system. However, none of these references combine fracture-stimulation equipment with a production system. Although *Albers* and *Lacy* both teach the well-known concept that proper well stimulation may increase oil and gas production, this does not explain why a POSITA would have been motivated to

⁹⁸ See, e.g., Ex. 1006 at 5:8-11 (“[T]he slurry is preferably pumped at a rate and pressure of 1 to 2 m³ /min and up to a design maximum of 70,000 kPa,” or about 6.3 to 12.5 bbl/min and about 10,150 psi.).

implement *Albers*'s fracture-stimulation equipment on *Crossley*'s production vessel as opposed to simply performing fracture-stimulation with *Albers*'s equipment before *Crossley*'s production system is put in place for oil and gas production, or with the well intervention system 170 of *Crossley* as discussed in Section XI.C below. As discussed above, this is how hydraulic fracturing and production operations are performed.

112. *Tolman* evidences this common practice and thus teaches away from the Petition's proposed combination. In particular, Tolman teaches that, "[i]f the planned stimulation treatments for the wells are complete, then the equipment associated with the stimulation treatments may be rigged-down and moved off the surface pad 102, as shown in block 320" for FIG. 3, before "run[ning] production tubing in each of the wells, as shown in block 322" and utilizing the wells "to produce hydrocarbons, as shown in block 324."⁹⁹ As discussed above, a POSITA would have been motivated to follow this common, well-known practice recognized in *Tolman* of performing fracture stimulation, removing the equipment used to perform fracture stimulation, and then equipping the well site to perform production operations (e.g., by running production tubing). The Petition's proposed

⁹⁹ Ex. 1008 at [0040], FIG. 3 (Step 320 "Move Stimulation Equipment," Step 322 ("Provide Production Tubing"), Step 324 "Produce Hydrocarbons")).

combination of *Albers*'s fracture-stimulation equipment with *Crossley*'s production vessel is inconsistent with this common, well-known practice.

113. Dr. Nikolaou and Petitioner have provided no rationale why a POSITA would piece together disparate equipment with disparate functions for disparate operations, absent the roadmap provided by the '394 Patent. Like Dr. Nikolaou's State of the Art and Background analysis, Dr. Nikolaou's analysis of the alleged motivations to combine relies on hindsight and the teachings of the '394 Patent to come up with the combination. Further, as discussed below, even Dr. Nikolaou's hindsight led combination fails to disclose all of the elements of the claim.

B. THE PETITION DOES NOT ESTABLISH A REASONABLE EXPECTATION OF SUCCESS IN COMBINING CROSSLEY AND ALBERS

114. As discussed above, Petitioner and Dr. Nikolaou rely on the combination of *Crossley*'s operations control system 180 with the fracture-stimulation equipment of *Albers* to allegedly render the claims of the '394 Patent obvious.¹⁰⁰ Even assuming a POSITA would have considered the combination, a POSITA would not have had a reasonable expectation of success in the combination.

115. Dr. Nikolaou and the Petition assert that there would have been a reasonable expectation of success in combining *Albers*'s fracture-stimulation equipment and *Crossley*'s operations control system because "each perform[] the

¹⁰⁰ Ex. 1003 at ¶ 48.

same function it has been known to perform (gas and oil production and well-stimulation techniques) and yielding not more than what one would expect from such an arrangement (centralized well operations including simultaneous and optimized well-stimulation techniques).”¹⁰¹ I disagree with this statement. *Crossley’s* operations control system (including its pumps, pipelines, valves, and manifold) would perform a **different** function in the Petition’s proposed combination of *Crossley* and *Albers*. As discussed above, *Crossley* relates to production operations, and *Crossley’s* operations control system is primarily concerned with producing fluids **from** the well. However, in the Petition’s proposed combination of *Crossley* and *Albers*, *Crossley’s* operations control system would instead be used for fracture stimulation and to introduce very large quantities of fluid **to** the well.

116. As discussed above, these are very different operations that use different equipment, different pressures, different fluid types, and different fluid volumes and rates. In evaluating whether *Crossley’s* operations control system could reasonably be used to introduce *Albers’s* stimulation fluid as proposed in the Petition, a POSITA would need to consider at least (i) whether the equipment in *Crossley’s* operations control system could withstand the pressures required to fracture a formation, (ii) whether the flowlines in *Crossley’s* operations control

¹⁰¹ Ex. 1003 at ¶ 58.

system are large enough to carry the volumes and rates required for fracturing fluids, and (iii) whether the power generated by *Crossley*'s production system would be sufficient to power the high horsepower pumps and other equipment required for fracturing operations in addition to *Crossley*'s existing equipment.

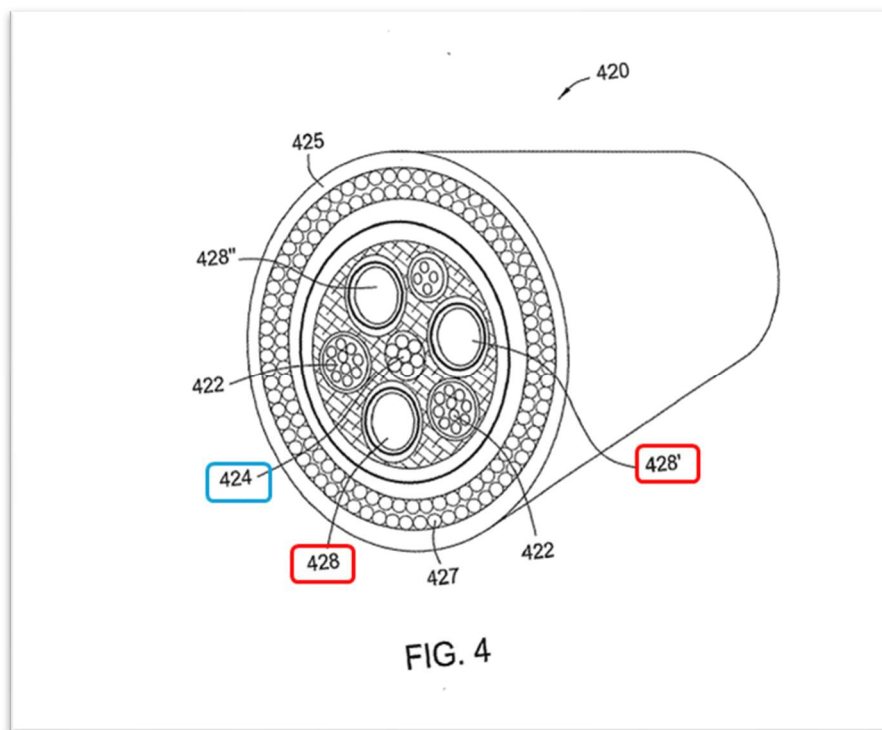
117. I have not seen any evidence that Dr. Nikolaou accounted for these considerations when proposing to combine *Crossley* and *Albers*. It is my opinion that, when accounting for these considerations, a POSITA would not have had a reasonable expectation of success in using *Crossley*'s production system to perform *Albers*'s fracture-stimulation techniques.

118. Dr. Nikolaou and the Petition rely on lines 428 and 428', shown in Figure 4 of *Crossley*, and annotated in red, for delivery of *Albers*'s well-stimulation fluids.¹⁰² Dr. Nikolaou then states, erroneously, the *Crossley/Albers* system "expressly permit the '*simultaneous*' distribution of well-stimulation fluids to a single well or to two different wells – one through 428 and second through 428'."¹⁰³

¹⁰² Ex. 1003 at ¶¶ 90-92

¹⁰³ Ex. 1003 at ¶ 91. There are other issues with this statement made by Dr. Nikolaou. As discussed in Section XI.D below, nowhere does *Crossley* disclose simultaneous distribution of two different fluids to two different wells. Additionally, as discussed in Section XI.C below, lines 428 and 428' are "preserved for the delivery of chemicals, such as hydrate inhibition fluids," not well stimulation fluids, Ex. 1005 at [0050], and *Crossley* elsewhere discloses the use of its intervention system 170

However, a POSITA would not have considered flow lines 428 and 428' to be suitable for flow of stimulation fluids and would not have expected success in using these lines for the distribution of stimulation fluids.



119. As discussed above in Section IX, the pressures, volumes and flowrates of well stimulation fluids are much higher than those of the production chemicals disclosed in *Crossley*. For example, as discussed above, production chemicals such as paraffin inhibitors are typically ounces / bbl of oil produced, or quarts / gallons per day. Corrosion inhibitors flow at rates of 4 oz. / hour. Production chemicals

for flowing a well stimulation fluid to individual wells thereby teaching away from the use of lines 428 and 428' for distributing well stimulation fluids.

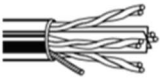
further only flow at pressures sufficient to overcome the pressure of the production system, typically hundreds of PSI. In contrast, stimulation fluids at the time of the '394 Patent typically had flowrates of bbl / min (10 – 100 bbl/min) and pressures around 10,000 PSI. The flowrate and pressure of the stimulation fluids requires flowlines much larger, and with higher pressure rating, than those that flow production chemicals.

120. A POSITA would have understood Figure 4 to show an umbilical line including “Line 424 [annotated in blue above] represents a digital cable line and may be a fiber optic line”¹⁰⁴ A comparison of the relative sizes of the “fluid distribution lines 428, 428” and digital / fiber optic line 424 show that they have similar sizes, with the fluid flow lines having an approximately 50% larger diameter. A POSITA would have recognized that a digital line with 7 communication conductors such as those shown in Figure 4, would be fractions of an inch in diameter. For example, Ethernet Cat. 5, which would have been common at the time of the '394 Patent, has 8 conductors, has a diameter of approximately 0.31” or smaller.¹⁰⁵ Similarly, a fiber optic cable with 6 fibers and a central core (7 conductors as shown in Figure 4) would

¹⁰⁴ Ex. 1005 at [0050].

¹⁰⁵ Ex. 2023 at p. 311.

have a diameter of less than ½”.¹⁰⁶ Accordingly, a POSITA reading *Crossley* would have understood lines 428 and 428’ to be fractions of an inch and diameter, with a pressure rating of a few hundred to maybe 1,000 PSI. Such lines would be completely unsuitable for use with *Albers*’s fracture stimulation fluid, which *Albers* discloses as being pumped at “a rate ... of 1 to 2 m³/min,” or about 264-528 gal/min or about 6.3 to 12.5 bbl/min, and “pressure of ... up to a design maximum of 70,000 kPa,” or about 10,000 PSI.¹⁰⁷

Description	Part No.	UL NEC/ C(UL) CEC Type	No. of Pairs	Standard Lengths		Standard Unit Wt.		Insulation Thickness		Nominal OD		Max. DCR (Ω/ 100m)	Max. DCR Unbal. (%)	Max. Cap. Unbal. (pF/ 100m)	Freq. (MHz)	Max. Atten. (dB/ 100m)	Min. PSUM NEXT (dB)	Min. PSUM ACR (dB/ 100m)	Min. PSUM ELFEXT (dB/ 100m)	Input Imped. (Ω)	Min. RL (dB)
				ft.	m	Lbs.	kg	Inch	mm	Inch	mm										
23 AWG Bonded-Pairs Solid Bare Copper • Patented E-Spline Center Member • Rip Cord • See Color Code Chart (below)																					
Non-Plenum • Polyolefin Insulation • PVC Jacket (Available in Red, Orange, Yellow, Green, Blue, Black, White or Dark Gray)																					
	7851A new	NEC: CMR CEC: CMR FT4	4	1000	304.8	40.0	18.2	.009	.23	.225	5.72	8.2	3.0	65.6	1	1.9	80.3	78.5	70.8	100±12	20.0
				A-1000	A-304.8	42.0	19.1			x	x				10	5.7	65.3	59.6	50.8	100±12	25.0
										310	7.87				31.25	10.2	57.9	47.7	40.9	100±15	25.0
															62.5	14.7	53.4	38.7	34.9	100±15	25.0
															100	18.9	50.3	31.4	30.8	100±15	25.0
															155	23.9	47.5	23.5	27.0	100±15	22.8
															200	27.5	45.8	18.3	24.8	100±15	21.7
															250	31.2	44.3	13.2	22.8	100±20	20.5
															350	37.7	40.2	4.5	19.9	100±22	19.8
															400	40.6	39.3	0.6	18.8	100±22	19.5
Jacket sequentially marked at 2 ft. intervals. U.S. Patents 5,606,151; 5,734,126; 5,789,711 and 6,297,454-B1 Third party verified to TIA/EIA-568-B.2-1, Category 6																					
Plenum • FEP Teflon® Insulation • Flamarrest® Jacket (Available in Red, Orange, Yellow, Green, Blue, Black, White or Gray)																					
	7852A new	NEC: CMP CEC: CMP FT6	4	1000	304.8	37.0	16.8	.008	.20	.215	5.46	8.2	3.0	65.6	1	1.9	80.3	78.5	70.8	100±12	20.0
				A-1000	A-304.8	39.0	17.7			x	x				10	5.7	65.3	59.6	50.8	100±12	25.0
										.290	7.37				31.25	10.2	57.9	47.7	40.9	100±15	25.0
															62.5	14.7	53.4	38.7	34.9	100±15	25.0
															100	18.9	50.3	31.4	30.8	100±15	25.0
															155	23.9	47.5	23.5	27.0	100±15	22.8
															200	27.5	45.8	18.3	24.8	100±15	21.7
															250	31.2	44.3	13.2	22.8	100±20	20.5
															350	37.7	40.2	4.5	19.9	100±22	19.8
															400	40.6	39.3	0.6	18.8	100±22	19.5
Jacket sequentially marked at 2 ft. intervals. U.S. Patents 5,606,151; 5,734,126; 5,789,711 and 6,297,454-B1 Third party verified to TIA/EIA-568-B.2-1, Category 6																					
ACR = Attenuation Crosstalk Ratio • DCR = DC Resistance • ELFEXT = Equal Level Far-end Crosstalk • NEXT = Near-end Crosstalk • PSUM = Power Sum • RL = Return Loss • UTP = Unshielded Twisted Pair(s) *PSUM ACR >0 is guaranteed to 460 MHz																					

¹⁰⁶ Ex. 2023 at p. 307.

¹⁰⁷ Ex. 1006 at 5:8-11.

Part No.	Jacket Material	No. of Fibers	Outer Diameter		Nominal Cable Weight	
			Inch	mm	Lbs./1000'	kg/km
Light Armored (RUS/PE-90 Listed)						
Single-mode/125/245 Micron (Core/Clad/Coating)						
L6006FM new	HDPE	6	.487	12.4	93	138
L6012FM new	HDPE	12	.487	12.4	93	138
L6024FM new	HDPE	24	.487	12.4	93	138
L6036FM new	HDPE	36	.487	12.4	93	138
LT048FM new	HDPE	48	.496	12.6	105	156
LT060FM new	HDPE	60	.496	12.6	105	156
LT072FM new	HDPE	72	.531	13.5	123	183
LT096FM new	HDPE	96	.623	15.8	148	220
LT120FM new	HDPE	120	.715	18.2	176	262
LT144FM new	HDPE	144	.785	19.9	204	308

121. Accordingly, a POSITA would not have expected success in using *Crossley's* lines 428, 428' to flow *Albers's* fracture stimulation fluid. Such fluids require lines with much larger sizes and rated for much higher pressures.¹⁰⁸ *Crossley* apparently recognized that this line would be unsuitable for stimulation fluid because, as discussed in Section XI.C below, *Crossley* presents an entirely different

¹⁰⁸ Considering the lines 428, 428' to be approximately 3/4" in diameter, a typical fracture stimulation fluid line (4") would have more than 28 times the cross-sectional area of the production chemical lines shown.

system (well intervention system 170) for injection of well stimulation fluids, such as acids.

122. To the extent that Petitioner argues that the above analysis would just require conventional “sizing up” of the chemical lines 428, 428’, a POSITA would not have considered simply “sizing up” these lines, which are part of the umbilical, to the sizes necessary for *Albers*’s fracture stimulation fluid with reasonable success. Converting lines 428, 428’ of *Crossley* to contain at least 2 (and 3 considering flowback in some dependent claims) fracture stimulation fluid lines of ~4” would mean that the umbilical would grow to be an unreasonable size. The current lines, based on the analysis above, are at most .75” in diameter. Adding three lines, each with 28 times more surface area, would expand the umbilical size to an unreasonable size, even without taking into consideration the increased pressure wall thickness necessary. Moreover, a POSITA would not have been motivated to use a “sized up” line for *Crossley*’s intended purposes of injecting production chemicals because it would require orders of magnitude more volume of those chemicals to fill the line as compared to *Crossley*’s existing lines, which would be cumbersome, costly, and potential wasteful. As discussed in Section XI.C below, *Crossley* expressly discloses a separate intervention system for use with well stimulation fluid (such as acid), likely in recognition of this fact.

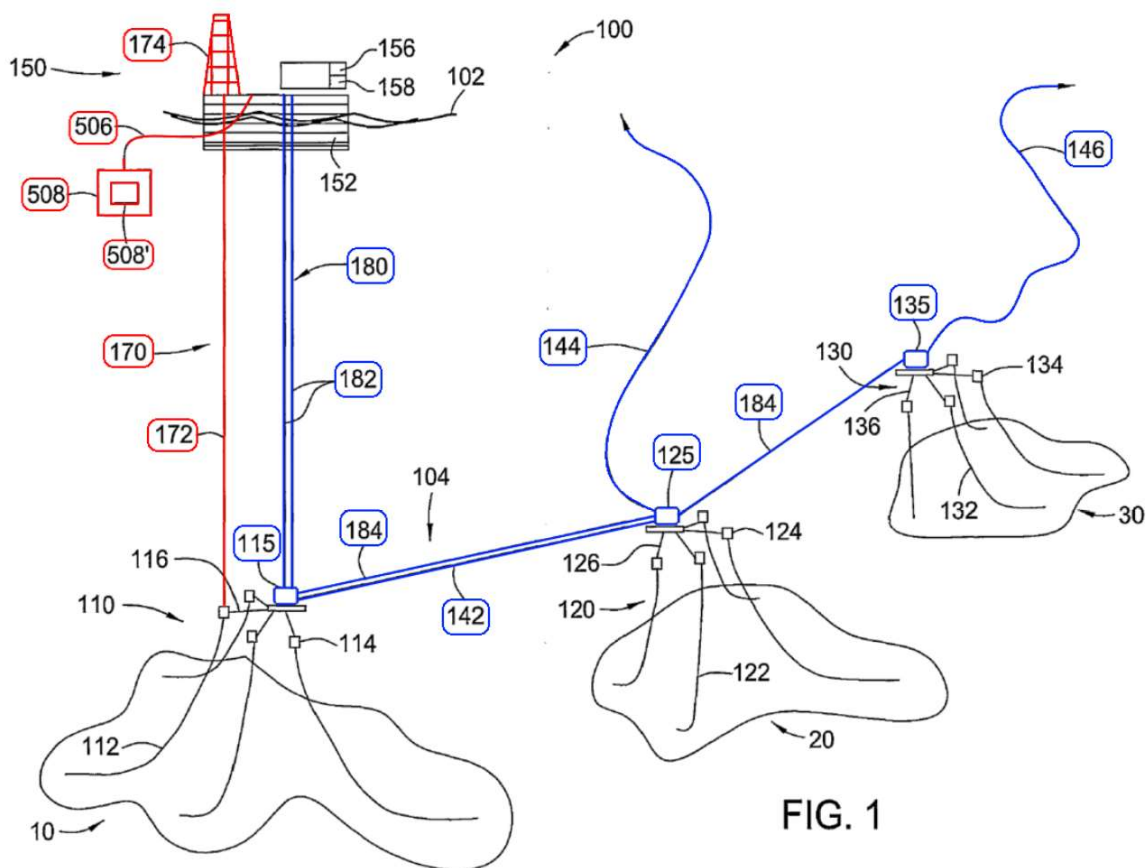
123. Additionally, according to *Albers*, its fracturing system operates, “at a rate and pressure of 1 to 2 m³ /min and up to a design maximum of 70,000 kPa,” which is about 6.3 – 12.5 bbl/min and ~10,150 PSI. This calculates to a hydraulic horsepower need of over 3,000 horsepower, which would be even greater when accounting for inefficiencies of the prime mover. The Petition has not established that a POSITA would have reasonably expected *Crossley’s* ship-born (i.e. size limited) “power delivery system 156” that is designed only to provide power to *Crossley’s* existing “control equipment” and “high power production equipment” to also provide sufficient power for *Albers’s* fracture-stimulation equipment.

124. Thus, in my opinion, when accounting for the fluid volumes and rates, operating pressures, and power requirements associated with *Albers’s* fracture-stimulation equipment, a POSITA would not have had a reasonable expectation of success in flowing *Albers’s* stimulation fluids through *Crossley’s* production system that is designed for lower fluid volumes and rates, pressures, and power requirements.

C. CROSSLEY TEACHES AWAY FROM THE PETITION’S PROPOSED COMBINATION OF CROSSLEY AND ALBERS

125. A close reading of the disclosure of *Crossley* shows that *Crossley* actually teaches against using the manifolds of *Crossley’s* “operations control system 180” to deliver well stimulation fluid because *Crossley* has a separate system for doing just that called “well intervention system 170.” As *Crossley* explains,

“[t]he system also comprises two separate systems: (1) *an operations control system* for providing subsea well-site operations such as power and communications” (annotated in blue in Figure 1 below), “and (2) *an intervention system* for conducting intervention services to an individual subsea well such as workover services and maintenance services” (annotated in red in Figure 1 below).¹⁰⁹ These two separate systems are used for different purposes.



126. *Crossley* discloses that its operations control system is used for “control operations,” which may include “the injection of chemicals such as hydrate, paraffin, or wax inhibitors into flow lines” and may also “include pumps and other electrically or hydraulically actuated equipment.”¹¹⁰ *Crossley* teaches that the “chemicals” being delivered to the wellheads through the manifold 115 are “chemicals, such as hydrate inhibition fluids.”¹¹¹ Elsewhere, *Crossley* describes these chemicals as “production chemicals” including “hydrate, paraffin, or wax inhibitors.”¹¹² Oil and gas extracted from subterranean formations contain hydrate, paraffin, and wax, and as the temperature of the oil and gas decreases as it approaches the surface, hydrate, paraffin, and wax can solidify and build up on production equipment and in the wellbore (e.g., on the production tubing). Hydrate, paraffin, or wax inhibitors are therefore pumped or injected into producing well in order to prevent build up and ensure smooth flow of oil and gas through the wellbore and equipment.

127. *Crossley*’s production system also contains a “well intervention system 170.” *Crossley* discloses that “[t]he well intervention system 170 is capable of providing workover functions to individual wells 112, 122, 132 downhole, and/or

¹¹⁰ Ex. 1005 at [0048].

¹¹¹ Ex. 1005 at [0050]

¹¹² Ex. 1005 at [0045]. See also Ex. 1005 at [0009].

maintenance functions to subsea equipment.”¹¹³ *Crossley* gives examples of “workover” (i.e., well intervention) functions that well intervention system 170 performs including “the replacement of tubing and the replacement of an electrical submersible pump.” *Crossley* further explains that “[w]orkover’ also refers to minor interventions that do not require the pulling of tubing,” such as “the running of logging equipment, changing of pressure or temperature gauges through the running of wireline or coiled tubing, *the injection of acid or other treating fluids*, the refilling of subsea pig launchers, and the like.”¹¹⁴

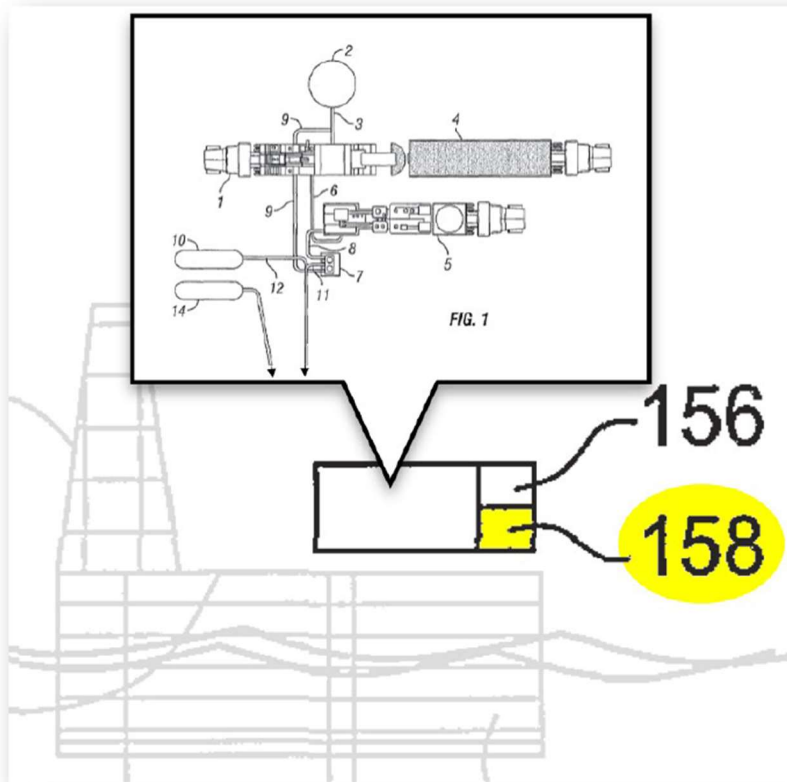
128. The Petition asserts that “[a] POSITA would have understood that by combining the teachings of Crossley with Albers, Albers’s fracture-stimulation equipment ... would have been implemented on Crossley’s ‘vessel 150’ ... in conjunction with the ‘control delivery system 158’,” which the Petition asserts is part of the “operations control system 180.”¹¹⁵ The Petition then includes the below figure in which *Albers’s* fracture-stimulation in *Albers’s* Figure 1 is superimposed onto Figure 1 of *Crossley*.¹¹⁶

¹¹³ Ex. 1005 at [0053]

¹¹⁴ Ex. 1005 at [0053].

¹¹⁵ Petition at 7, 11-12.

¹¹⁶ Petition at 11-12.



129. I disagree with the Petition’s assertion. The Petition and Dr. Nikolaou completely ignore *Crossley’s* well intervention system, which is the portion of *Crossley’s* system that introduces a well stimulation fluid to a well and thus performs the function most similar to *Albers’s* fracture-stimulation equipment. In particular, as noted above, *Crossley’s* well intervention system is used for “*the injection of acid or other treating fluids.*”¹¹⁷ As discussed above in Section IX.C.4 above, it was, and still is, common that a production well would need to be re-stimulated as part of ongoing maintenance efforts to continue the production of oil and gas. One such

¹¹⁷ Ex. 1005 at [0053].

stimulation technique is acid fracturing in which an acid is pumped into a formation causing it to degrade the formation's rock. Thus, a POSITA would have understood *Crossley's* teaching of "the injection of acid or other treating fluids" for intervention during production operations to be acid fracturing and other reservoir stimulation techniques, which involves flowing a well stimulation fluid.

130. As discussed in Section IX.C.4 above, a POSITA would have understood that other reservoir stimulation techniques used in well maintenance includes hydraulic fracturing, such as with traditional water-based fracturing fluids or the gaseous (carbon dioxide and nitrogen) fracturing fluids disclosed in *Albers*. Accordingly, if a POSITA would have somehow been motivated to combine *Crossley* and *Albers* (which they would not as discussed above), a POSITA would have looked at replacing or combining the "well intervention system 170" of *Crossley* with *Albers's* fracture-stimulation equipment because both serve the same function, namely, introducing stimulation fluids to stimulate the wellbore.

131. Furthermore, as discussed above, a POSITA would not have looked to *Crossley's* operations control system 180, its chemical delivery lines 428 and 428', or its collection manifolds 115, 125, 135, all of which are designed to deliver small quantities of production chemicals (on the order of quarts to barrels per day), when attempting to introduce the large quantities of *Albers's* stimulation fluids (on the order of barrels per minute). These lines and manifolds of *Crossley's* operations

control system are not designed to transport well stimulation fluids to the wellbores. *Crossley* recognizes this and teaches a different system for delivery of well stimulation fluids, thereby teaching away from using the operations control system, its chemical delivery lines, and its manifolds for delivery of well stimulation fluids.

132. I understand that the Institution Decision notes that *Crossley* “teaches that the control delivery system can be used for the treatment of the wellbore.”¹¹⁸ “Treating” and “treatment” as used in *Crossley* are generic terms commonly used in the oil and gas industry to refer to the introduction of chemicals or fluids into a wellbore for any number of purposes. Depending upon the chemicals or fluids used, a POSITA would have understood the particular “treatment” that is occurring and its purpose. More specifically, a POSITA reading *Crossley* would have readily understood that the production chemicals introduced by *Crossley*’s operations control system are for the purpose of preventing buildup during oil and gas production and that the acid and other treating fluids of *Crossley*’s well intervention system are for the purpose of reservoir stimulation to prolong oil and gas production. A POSITA also would have understood that these are completely different purposes. As discussed above, a POSITA further would have understood *Albers*’s fracture-stimulation fluid to serve the same purpose as the fluid used by *Crossley*’s

¹¹⁸ Institution Decision at 40.

intervention system and a different purpose than the fluid used by *Crossley's* operations control system.

133. As discussed above, *Crossley* does, in fact, already disclose flowing a well stimulation fluid (i.e., acid or other treating fluids) to a well even without being combined with *Albers* using its well intervention system 170. Similar to conventional intervention and stimulation systems, *Crossley's* well intervention system 170 connects to only one well at a time. *Crossley* discloses “[t]he well intervention system 170 is capable of providing workover functions to *individual wells* 112, 122, 132 downhole, and/or maintenance functions to subsea equipment.”¹¹⁹ Further, *Crossley* discloses “[t]he intervention system 170 includes any known support structure 174 for supporting a working string (not shown). The working string is deliverable into a wellbore of *an individual well*, e.g., well 112, for performing at least one of workover services and maintenance services. The working string typically will have a tool string (also not shown) for conducting operations within the wellbore. The working string and tool string are lowered into the wellbore through the workover riser 172.”¹²⁰

¹¹⁹ Ex. 1005 at [0053].

¹²⁰ Ex. 1005 at [0061]. See also Ex. 1005 at Abstract, [0010], [0020], [0025], [0026], [0030], [0037], [0038], [0056], Cl. 1 (disclosing intervention services for only one “an individual well” at a time).

¹²¹ Ex. 1006 at 4:1-11.



135. *Albers* discloses that fluid leaving sand intensifier unit and the nitrogen/carbon dioxide storage tanks are connected to a manifold connection “which is in turn connected to a first wellhead conduit (13) [annotated in blue] that extends directly to the wellhead.”¹²¹ All other reference to “the well” or “a well” in

Albers also disclosed only a single connection to an individual well.¹²² There is no suggestion in *Albers* that there are connections to multiple wells, much less simultaneously flowing well stimulation fluid to multiple wells.

136. Accordingly, if a POSITA would have at all been motivated to combine *Albers*'s fracture-stimulation equipment with *Crossley*'s production system, a POSITA would have been led to combine *Albers*'s fracture-stimulation equipment with *Crossley*'s well intervention system that already serves the same purpose of stimulating a wellbore in order to enhance oil and gas production. Indeed, absent the roadmap provided by the '394 Patent, Dr. Nikolaou and Petitioner have provided no rationale why a POSITA would ignore *Crossley*'s well intervention system and its use to treat "an individual well."

137. As a result, a POSITA would have been led away from the claims of the '394 Patent, in particular, limitation 1[d] which recites "means for simultaneously flowing: a first stimulation fluid to the first well and not to the second well; and a second stimulation fluid to the second well and not to the first well," because *Crossley*'s well intervention system is used for conducting intervention services (e.g., introducing a well stimulation fluid) to an individual well (i.e., one well at a time). The use of *Crossley*'s well intervention system does not meet at least

¹²² See, e.g., Ex 1006 at 3:1-21.

limitation 1[d] of the '394 Patent, and thus, *Crossley* teaches away from the claimed invention.

D. THE COMBINATION OF CROSSLEY AND ALBERS DOES NOT DISCLOSE, TEACH, OR SUGGEST ALL LIMITATIONS OF THE CLAIMS OF THE '394 PATENT

1. Independent Claim 1

138. Claim 1 contains the following limitations, which have been subdivided in the same manner that Dr. Nikolaou subdivided them:

1[pre]: 1. A system for centralized well operations comprising:

1[a]: a well treatment operations factory which manufactures and pumps a well stimulation fluid;

1[b]: a first connection between a first well and the well operations factory;

1[c]: a second connection between a second well and the well operations factory; and

1[d]: means for simultaneously flowing: a first stimulation fluid to the first well and not to the second well; and a second stimulation fluid to the second well and not to the first well;

1[e]: wherein the first stimulation fluid and the second stimulation fluid have different compositions.

a. The combination of Crossley and Albers does not disclose or suggest limitation 1[d]

139. Limitations 1[b] and 1[c] require connections between the well treatment operations factory and both a first well and a second well. Limitation 1[d] requires that “means for simultaneously flowing” a first stimulation to the first well, and not to the second well, and a second stimulation fluid to the second well and not

the first well. The stimulation fluid “flows” by being pumped by the well treatment operations factory as disclosed in limitation 1[a].

140. *Crossley* discloses that “[t]he clustering of wells also allows for one or more control lines to be run from a single location at the ocean surface, downward to the clustered wells.”¹²³ With respect to the control line, *Crossley* discloses that “[t]he control line ties into a control module on the manifold, and then branch to the various wellheads.”¹²⁴ *Crossley* further discloses that “[s]uch a control line allows for the monitoring and control of valves, gauges, and other subsea equipment” and “allow[s] for one or more power lines or chemical delivery lines to be delivered from the ocean surface, downward to the clustered wells.”¹²⁵

141. The Petition, relying on Dr. Nikolaou, claims that “Crossley’s vessel 150, through its control system 180, controls the configuration of manifolds 115, 125, and 135, as well as corresponding valves to direct fluid to selected wells.”¹²⁶ As described above in Section XI.A, *Crossley* discloses that manifolds 115, 125, 135 are not for directing fluids *to* selected wells, but are “collection manifolds” where

¹²³ Ex. 1005 at [0005].

¹²⁴ Ex. 1005 at [0005].

¹²⁵ Ex. 1005 at [0005].

¹²⁶ Petition at 27-28 (citing Ex. 1003 at ¶ 84).

“production fluids from a well-site can be commingled for unitary transportation to another location” like a gathering facility.¹²⁷

142. I disagree with Dr. Nikolaou’s assertion that “a POSITA would understand that the manifolds as used in *Crossley*, are the type of equipment that would enable the use of ‘simultaneous or concurrent operations in the stimulation of multiple wells.’”¹²⁸ I note that Dr. Nikolaou’s assertion relies on *Tolman*, which relates to fracture-stimulation operations¹²⁹ and, as discussed above, distinguishes the equipment used in those operations from equipment used in production operations such as in *Crossley*. Thus, *Tolman* does not support Dr. Nikolaou’s assertion. I further understand that *Tolman* does not qualify as prior art, and thus, it is improper for Dr. Nikolaou to even rely on *Tolman*. In my opinion, contrary to Dr. Nikolaou’s assertion, a POSITA would not have understood *Crossley*’s manifolds that are used in production operations to enable stimulation of any well, much less multiple wells, for all of the reasons discussed above, including the differences between stimulation and production operations and *Crossley*’s teaching of a separate well intervention system for stimulation of a well.

¹²⁷ Ex.1005 at [0045].

¹²⁸ Ex. 1003 at ¶ 85 (citing Ex. 1008).

¹²⁹ Ex. 1008 at Title, [0006].

143. The Petition and Dr. Nikolaou also claim that *Crossley's* “manifolds are used to **selectively** deliver fluids from vessel 150,” and that “by **selectively** controlling *Crossley's* manifolds, ... *Crossley's* system would be configured to direct the field-optimized well-stimulation fluids of *Albers* to flow using different paths.”¹³⁰ Despite the Petition’s and Dr. Nikolaou’s emphasis on “selectively,” the only disclosure of “selectively” in *Crossley* relates to “a surface vessel control link *selectively connectible* with the control module at the first well-site and the control module at a second well-site so that control operations may be conducted for both the first well-site and the second well-site from either well-site.”¹³¹ This disclosure has nothing to do with controlling how fluids are directed to particular subsea equipment or wellbores located at the first well-site or the second-well site. Rather, *Crossley* states “[t]he terms ‘detachable’ and ‘selectively connectible’ may be used interchangeably with the term ‘reconnectible.’”¹³² Thus, the “selectively connectible” disclosure upon which the Petition and Dr. Nikolaou rely simply means that the control link may be connected to a first well-site, a second well-site, or both.

¹³⁰ Petition at 28-29 (citing Ex. 1003 at ¶¶ 85-86) (emphasis in original).

¹³¹ Ex. 1005 at [0028].

¹³² Ex. 1005 at [0035].

It does not amount to selective control over manifolds that would enable simultaneous flow of one fluid to one well and another fluid to another well.

144. *Crossley* does not disclose any details on which fluids are delivered to each well-site or each well within each well-site. More importantly, *Crossley* does not disclose simultaneous flowing a first fluid to a first well, pad, or plurality of wells and not to a second well, pad, or plurality of wells and a second fluid to the second well, pad, or plurality of wells and not the first well, pad, or plurality of wells as required by the claims of the '394 Patent.

145. Dr. Nikolaou and the Petition also cite paragraph [0050] which contains a single statement that “[c]hemicals may be delivered from the lines 428, 428’ and then through the manifold 115 for treatment of flow lines, valves, and even the wellbores as appropriate”¹³³ to suggest that the manifolds can be used to deliver *Albers’s* well stimulation fluid to the wells. While line 428 and line 428’ would simultaneously deliver two fluid (i.e., production chemicals) to the manifold 115, a POSITA would not have understood these lines to permit the simultaneous flow of (i) a first fluid in line 428 to a first well, pad, or plurality of wells and not to a second well, pad, or plurality of wells, and (ii) a second fluid in line 428 to the second well, pad, or plurality of wells and not the first well, pad, or plurality of wells as the

¹³³ Ex 1005 at [0050].

Petition and Dr. Nikolaou assert. There is nothing in *Crossley* that teaches or suggests such flow.

146. First, while *Crossley* generally discloses that a valve may be “associated with the collection manifold, e.g., 115 or 125, or with an individual well, e.g., 112, 122,”¹³⁴ *Crossley* does not disclose, teach, or suggest any valves on chemical delivery lines 428, 428’. Rather, a POSITA would have understood, at most, *Crossley*’s disclosure to mean that the chemicals in both line 428 and line 428’ travel together into manifold 115 and then are distributed together into all flowlines, valves, or wellbore that are open.

147. I understand the Board’s Institution Decision states: “We do not agree, based on the current record, that *Crossley* teaches a control line can only control a valve associated with all chemical delivery lines, as opposed to a valve associated with each delivery line.”¹³⁵ However, *Crossley* does not disclose, teach, or suggest any valves associated with its chemical delivery lines. Rather, a POSITA would have understood the valves to which *Crossley* refers are located on: (i) each collection manifold to control the flow of production fluids into the manifold from the

¹³⁴ Ex. 1005 at [0057]; see also Ex. 1005 at [0004] (“It is also understood that the trees 114, 124, 134 of each well have valves for controlling or shutting off fluid flow from the wellbores.”).

¹³⁵ Institution Decision at 17.

individual wells and out of the manifold to the unitary transport flowline, and (ii) on the tree of each individual well to control the flow of production fluids into and out of the well.¹³⁶ Assuming the valves to a manifold are open, when “[c]hemicals [are] delivered from lines 428, 428’ and then through the manifold,” as disclosed in *Crossley*, a POSITA would have understood that those chemicals would flow from the manifold to any individual well that also has an open valve and any closed valves would prevent fluid from flowing to the well. For there to be simultaneous flow to both well 112 and well 122 (or, alternatively, a second well within well-site 110), as proposed in the Petition, then the valves to both well 112 and well 122 must be open and whatever fluid is traveling from vessel 150 through in lines 428, 428’ of connection 182 would necessarily flow through the manifold and to both wells.

148. Second, even if there were separately controlled valves associated with each chemical delivery line 428 and 428’, neither Petition nor Dr. Nikolaou has explained how such valves could even be used to simultaneously flow: (i) a first fluid in line 428 to a first well, pad, or plurality of wells and not to a second well, pad, or plurality of wells, and (ii) a second fluid in line 428” to the second well, pad, or plurality of wells and not the first well, pad, or plurality of wells, or why a POSITA would have been motivated to do. For instance, there is no disclosure,

¹³⁶ Ex. 1005 at [0044].

teaching, or suggestion that line 428 is only connected to a first well and line 428' is only connected to a second well, and the Petition offers no arrangement of valves that could permit such flow. Dr. Nikolaou claims lines 428, 428' "expressly permit" simultaneous distribution to two different wells, as required by the claims of the '394 Patent, but he does not provide any explanation for that statement.

149. Furthermore, given *Crossley's* disclosure that "production fluids from a well-site can be commingled for unitary transportation to another location" like a gathering facility,¹³⁷ a POSITA, based on the teachings of *Crossley*, would not have been concerned with simultaneously delivering two different production chemicals to two different wells, pads, or plurality of wells as recited in the challenged claims because those production chemicals are mixed with the production fluids that end up commingled. For example, even if the production fluid from one well required a specific production chemical and the production fluid from another well required a different production chemical (which *Crossley* does not teach, suggest, or disclose), both production chemicals would ultimately be needed in the manifold and unitary transport lines in which the production fluids are commingled.

¹³⁷ Ex. 1005 at [0045].

150. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach, or suggest limitation of 1[d] of the '394 Patent.

b. The combination of *Crossley* and *Albers* does not disclose, teach, or suggest limitation 1[e]

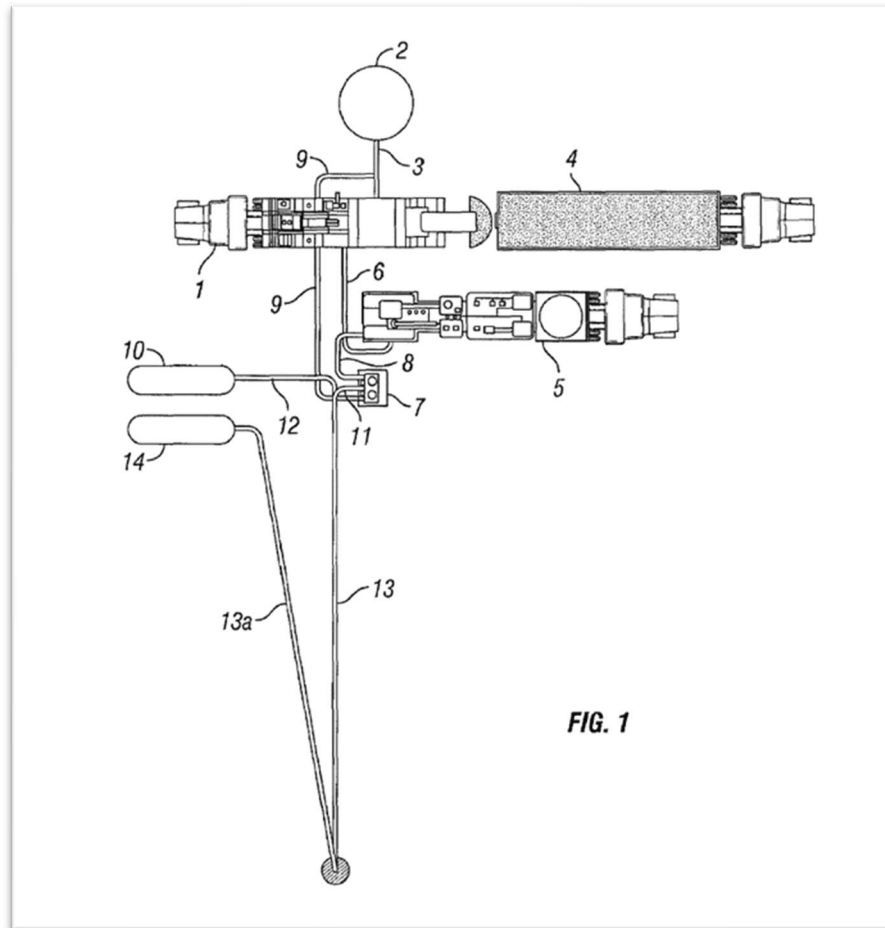
151. Limitation 1[e] requires that the well stimulation fluids, which are simultaneously flowed to the first well (or pad or plurality of wells in the other independent claims) and the second well (or pad or plurality of wells in the other independent claims), have different compositions. Neither *Albers* nor *Crossley* teach or suggest such an arrangement. Dr. Nikolaou relies on a disclosure in *Albers* that fluid composition can be changed based on the requirements of different formations. However, Claim 1 requires more than just changing fluid composition based on different formations, it requires that the different fluids flow to the two different wells simultaneously.

152. The system of *Albers* manufactures the stimulation fluid and immediately delivers it to the well on the fly. For example, *Albers* describes the manufacture of its well stimulation fluid as follows:¹³⁸

The sand trailer (4) typically includes one or more proppant containers (not shown), which are used to transfer proppant to the mixing tub (not shown) of the blender unit (1). The blender unit (1) is shown further connected to a conventional high-pressure pump (5) by a second conduit (6). The high pressure pump (5) is in turn connected to a conventional sand intensifier unit (7) by a third conduit (8). The sand intensifier unit (7) is then connected back

¹³⁸ Ex. 1006 at 3:61-4:11.

to the first conduit (3), and subsequently the fluid storage device (2), via a reflux conduit (9). A first nitrogen/carbon dioxide storage tank and pump (10) is schematically shown connected to a short conduit (11) extending from the sand intensifier unit (7). The first nitrogen/carbon dioxide storage tank and pump (10) is connected to the short conduit (11) via a fourth conduit (12). Those connections are then attached to a manifold connection (not shown), which is in turn connected to a first wellhead conduit (13) that extends directly to the wellhead.



153. There is no storage of the fracturing fluid after it is mixed. The fluid is finally mixed in the manifold (not shown) and then connects directly to the wellhead conduit 13 and then to the wellhead. Accordingly, in the system of *Albers*, the fluid is blended and then immediately directed to the well.

154. In order for the system of *Albers* to flow two different fluids simultaneously to two different wells, as claim 1[e] requires, the different fracturing fluids must be created simultaneously. The system of *Albers* only contains one blending system (blender, manifold, conduits etc.) and would be incapable of manufacturing two different well stimulation fluids simultaneously. The different fluid compositions of *Albers* are manufactured for different formations over time and space, and not manufactured or flowed simultaneously.¹³⁹ There is no suggestion that the system of *Albers*, even in combination with *Crossley*, would be configured to either manufacture different fluids simultaneously, or flow the fluids simultaneously to different wells.

155. I understand that the Institution Decision states that “there is no evidence that such a modification or duplication of *Albers* system to prepare two separate compositions is beyond the skill of one of ordinary skill in the art.”¹⁴⁰ However, neither the Petition nor Dr. Nikolaou have offered any such modification. Furthermore, as explained above, *Albers*’s fracture-stimulation equipment requires significant power and duplicating that equipment would likewise duplicate the power requirements. As further explained above, a POSITA would not have had a

¹³⁹ See, e.g., Ex. 1006 at Fig. 6, Fig. 8, 6:64-7:26.

¹⁴⁰ Institution Decision at 19.

reasonable expectation of success that *Crossley*'s power delivery system 156 would be capable of powering *Albers*'s fracture-stimulation equipment at all, much less in duplicate.

156. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest limitation 1[e] of the '394 Patent.

2. Dependent Claim 2

157. Dependent Claim 2 of the '394 Patent requires "wherein the means for simultaneously flowing treatment fluid comprises a manifold." Dependent Claim 2 depends from Claim 1 and contains all the limitations of Claim 1. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 1. For example, the combination of *Crossley* and *Albers* does not disclose flowing different treatment fluids to different wells, much less flowing them simultaneously. Additionally, there is no suggestion in either *Crossley* or *Albers* that the manifolds described are used to flow the two different fluids to two different wells simultaneously. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 2.

3. Dependent Claim 3

158. Dependent Claim 3 depends from Claim 2, which further depends from Claim 1, and contains all the limitations of Claim 1 and Claim 2. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all

limitations of Claim 1 or Claim 2. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 3.

4. Dependent Claim 4

159. Dependent Claim 4 depends from Claim 3, which further depends from Claim 1 and Claim 2, and contains all the limitations of Claims 1 - 3. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claims 1 - 3. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 4.

5. Dependent Claim 5

160. Dependent Claim 5 depends from Claim 4, which further depends from Claims 1 - 3, and contains all the limitations of Claims 1 - 4. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 - 4. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 5.

6. Dependent Claim 6

161. Dependent Claim 6 requires “Claim 8 requires the system to also contain “a chemical storage system wherein the chemical storage system is operable to connect to the blending unit.” Dependent Claim 6 depends from Claim 5, which further depends from Claims 1 - 4, and contains all the limitations of Claims 1 - 5.

As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 - 5.

162. Additionally, neither Dr. Nikolaou nor Petitioner make even a token effort to show that *Crossley*'s "power for control equipment" and "electrical power for high power production equipment" would be sufficient to power both the production equipment, the well intervention system, and the added fracturing equipment from *Albers*. According to *Albers*, the fracturing system operates, "at a rate and pressure of 1 to 2 m³ /min and up to a design maximum of 70,000 kPa, [$\sim$ 6.3 – 12.5 bbl/min, $\sim$ 10,150 psi]"¹⁴¹ This calculates to a hydraulic horsepower need of over 3,000 horsepower. Taking into account inefficiencies of the prime mover, this need would be even greater. Neither Petitioner nor Dr. Nikolaou provide a rationale or explanation how a ship-born (i.e. size limited) power system already powering control systems and other "high power" equipment could handle an additional 3,000 Hp and still perform its other tasks (i.e. production).

163. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, suggest the limitations of Claim 6.

¹⁴¹ Ex. 1006 at 5:8-11.

7. Dependent Claim 7

164. Dependent Claim 7 depends from Claim 5, which further depends from Claims 1 – 5, and contains all the limitations of Claims 1 – 6. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 - 6. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, suggest the limitations of Claim 7.

8. Dependent Claim 8

165. Dependent Claim 8 requires “a chemical storage system wherein the chemical storage system is operable to connect to the blending unit.” Dependent Claim 8 depends from Claim 4, which further depends from Claims 1 - 3, and contains all the limitations of Claims 1 - 4. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claims 1 - 4.

166. Further, *Albers*’s fracture-stimulation equipment on which the Petition relies does not include “a chemical storage system wherein the chemical storage system is operable to connect to the blending unit.” The ’394 Patent explains that “the blending unit 105 is connected to the *chemical storage system* 112, the ***proppant storage system*** 106, a ***water source*** 202, and a pumping grid 111 and may prepare a

fracturing fluid ... by mixing and blending fluids and chemicals”¹⁴² Thus, in the ’394 Patent, the chemical storage system is separate and distinct from the water source, and each is connected to the blending unit.

167. *Albers* discloses that its “blender unit draws fluid from a *fluid storage device*, draws proppant from a *sand trailer*, and mixes the two in a blender tub to form a slurry.”¹⁴³ Thus, *Albers* does not disclose a chemical storage system operable to connect to the blending unit. The Petition nevertheless reads *Albers*’s “fluid storage device” on the “chemical storage system” of Dependent Claim 8.¹⁴⁴ *Albers*’s fluid storage device contains “an uncomplexed **fluid**, which ... is preferably clay-stabilized or gelled water but can be any suitable fluid including a methanol water or a hydrocarbon-based fluid.”¹⁴⁵ A POSITA would have understood these fluids to be the base fluid of fracturing fluids (e.g., water with chemicals), not chemicals alone as described in the ’394 Patent. The ’394 Patent describes chemicals as “crosslinkers, gelling agents, viscosity altering chemicals, PH buffers, modifiers, surfactants,

¹⁴² Ex. 1001 at 4:22-28.

¹⁴³ Ex. 1006 at 2:1-4.

¹⁴⁴ Petition at 41-42.

¹⁴⁵ Ex. 1006 at 4:51-56.

breakers, and stabilizers.”¹⁴⁶ These chemicals are distinct from the base fluids as described by the ‘394 Patent in which the fracturing fluid is prepared “by mixing and blending fluids and chemicals at continuous rates according to the needs of a well formation.”¹⁴⁷

168. *Albers* does not disclose, teach, or suggest a separate chemical storage system that contains any chemicals before they are mixed with water in the blender. The Petition and Dr. Nikolaou also do not provide any reason a POSITA would have been motivated to modify *Albers*’s fracture-stimulation equipment to include one as opposed to, for example, pre-mixing the chemicals disclosed in *Albers* (e.g., clay stabilizer or gel) into the water offsite.

169. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 8.

9. Dependent Claim 9

170. Dependent Claim 9 requires “the well operations factory comprises a power unit operable to connect to the manifold, pumping grid, blending unit, chemical storage system, the first well, and the second well.” Dependent Claim 9 depends from Claim 8, which further depends from Claims 1 - 4, and contains all

¹⁴⁶ Ex. 1001 4:34 – 37.

¹⁴⁷ Ex 1001 4:25 – 28.

the limitations of Claims 1 – 4 and Claim 8. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 – 4 and 8. Additionally, as discussed above for Claim 6, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest a power unit operable to connect to the equipment recited in Claim 9. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 9.

10. Dependent Claim 10

171. Dependent Claim 10 depends from Claim 2, which further depends from Claim 1, and contains all the limitations of Claims 1 and 2. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest and limitations of Claims 1 and 2. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 10.

11. Dependent Claim 11

172. Dependent Claim 11 depends from Claim 10, which further depends from Claims 1 and 2, and contains all the limitations of Claims 1, 2, and 10. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1, 2 and 10. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 11.

173. Further, a POSITA would not have been motivated to use *Crossley's* system as a stimulation fluid flowback system as required by Claim 11. . In order to

understand the limitations of Claim 11 in context, the limitations already imputed by Claims 1, 2 and 10 are included with Claim 11 below.

1[pre]: 1. A system for centralized well operations comprising:

1[a]: a well treatment operations factory which manufactures and pumps a well stimulation fluid;

1[b]: a first connection between a first well and the well operations factory;

1[c]: a second connection between a second well and the well operations factory; and

1[d]: means for simultaneously flowing: a first stimulation fluid to the first well and not to the second well; and a second stimulation fluid to the second well and not to the first well;

1[g]: wherein the first stimulation fluid and the second stimulation fluid have different compositions.

2. The system of claim 1 wherein the means for simultaneously flowing treatment fluid comprises a manifold.

10. The system of claim 2 wherein the first connection is operable to deliver a fluid from the first well to the manifold.

11. The system of claim 10 wherein the fluid comprises a stimulation fluid.

174. Claim 11 requires more than just a “a flowback and reuse system” as

Dr. Nikolaou suggests. It requires that different stimulation fluids be pumped to the first and second well simultaneously using a manifold, and that stimulation fluid be delivered from the well back to the same manifold. The Petition asserts that it would have been obvious to use *Crossley’s* flow line jumper, which ties into the collection

manifold, to deliver a stimulation fluid from the first well to the manifold (i.e., to flowback the stimulation fluid).¹⁴⁸

175. *Crossley* teaches specifically, as Petitioner points out, that its collection manifolds are used so that “production fluids from a well-site can be commingled for unitary transport to another location.”¹⁴⁹ A POSITA would have understood, particularly in light of the teachings of *Crossley*, that production fluids include “produced gas” and “produced liquids” and are hydrocarbons collected for processing and sale. A POSITA would not, in light of the knowledge of the POSITA or the teachings of *Crossley* or *Albers*, have understood “production fluids” to encompass stimulation fluids. As discussed above in Section IX.C, production fluids are collected after stimulation occurs. Any “flowback” of stimulation fluids would not be performed by the production equipment, but by the fracturing equipment, such as the well intervention system 170 of *Crossley*. Neither the Petition nor Dr. Nikolaou provide any rationale why a POSITA would have viewed “production fluids” to encompass a stimulation fluid.

¹⁴⁸ Petition at 62-64.

¹⁴⁹ Ex. 1005 at [0045].

176. Further, given *Crossley*'s teaching that "production fluids from a well-site can be commingled for unitary transport to another location,"¹⁵⁰ a POSITA would not have been motivated to use *Crossley*'s system to flowback stimulation fluid because doing so would result in either: (1) fracture-stimulation fluid flowed back from one well being commingled with production fluids from another well, thereby adding further time and expense to separate the fluids, or (2) if commingling these two fluids was to be avoided, significant delay of production while fracture-stimulation fluid was flowed back from every well in *Crossley*'s cluster of wells. It can take over a week to flowback a single well, and given the number of wells disclosed in *Crossley*, production could be delayed for months in such instance. An operation would have been motivated to avoid such delay by using separate fracturing and production equipment as was commonly done, as discussed above.

177. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach or suggest Claim 11.

12. Dependent Claim 12

178. Dependent Claim 12 depends from Claim 2, which further depends from Claim 1, and contains all the limitations of Claims 1 and 2. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all

¹⁵⁰ Ex. 1005 at [0045].

limitations of Claims 1 and 2. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, suggest the limitations of Claim 12.

13. Dependent Claim 13

179. Dependent Claim 13 is similar to Dependent Claim 11 except it relates to the “second connection” and “second well” rather than the “first connection” and “first well” in Claim 11. Dependent Claim 13 depends from Claim 12, which further depends from Claims 1 and 2, and contains all the limitations of Claims 1, 2, and 12. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims, 1, 2, and 12. Further, the limitations of Claim 13 are missing from the combination for the same reasons as those discussed regarding Claim 11 above. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 13.

14. Dependent Claim 14

180. Dependent Claim 14 depends from Claim 2, which further depends from Claim 1, and contains all the limitations of Claims 1 and 2. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 and 2. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 14.

15. Dependent Claim 15

181. Dependent Claim 15 depends from Claim 14, which further depends from Claims 1 and 2, and contains all the limitations of Claims 1, 2, and 14. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1, 2 and 14. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 15.

16. Dependent Claim 16

182. Dependent Claim 16 requires “a third connection between the manifold and the first well.” Dependent Claim 16 depends from Claim 2, which further depends from Claim 1, and contains all the limitations of Claims 1 and 2. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1 and 2.

183. Further, neither *Crossley* nor *Albers* discloses, teaches, or suggests a “third connection between the manifold and the first well.” Dr. Nikolaou’s analysis, while difficult to follow, seems to imply that because *Crossley* discloses there may be one or more strings of production tubing or production liners in each wellbore that, somehow, there are multiple connections between the well and the manifold. This, however, is not correct. A POSITA would have understood that production tubing or production liners each terminate at the wellhead, not at the manifold. *Crossley* makes this clear, even in the same sections Dr. Nikolaou quotes, if they are

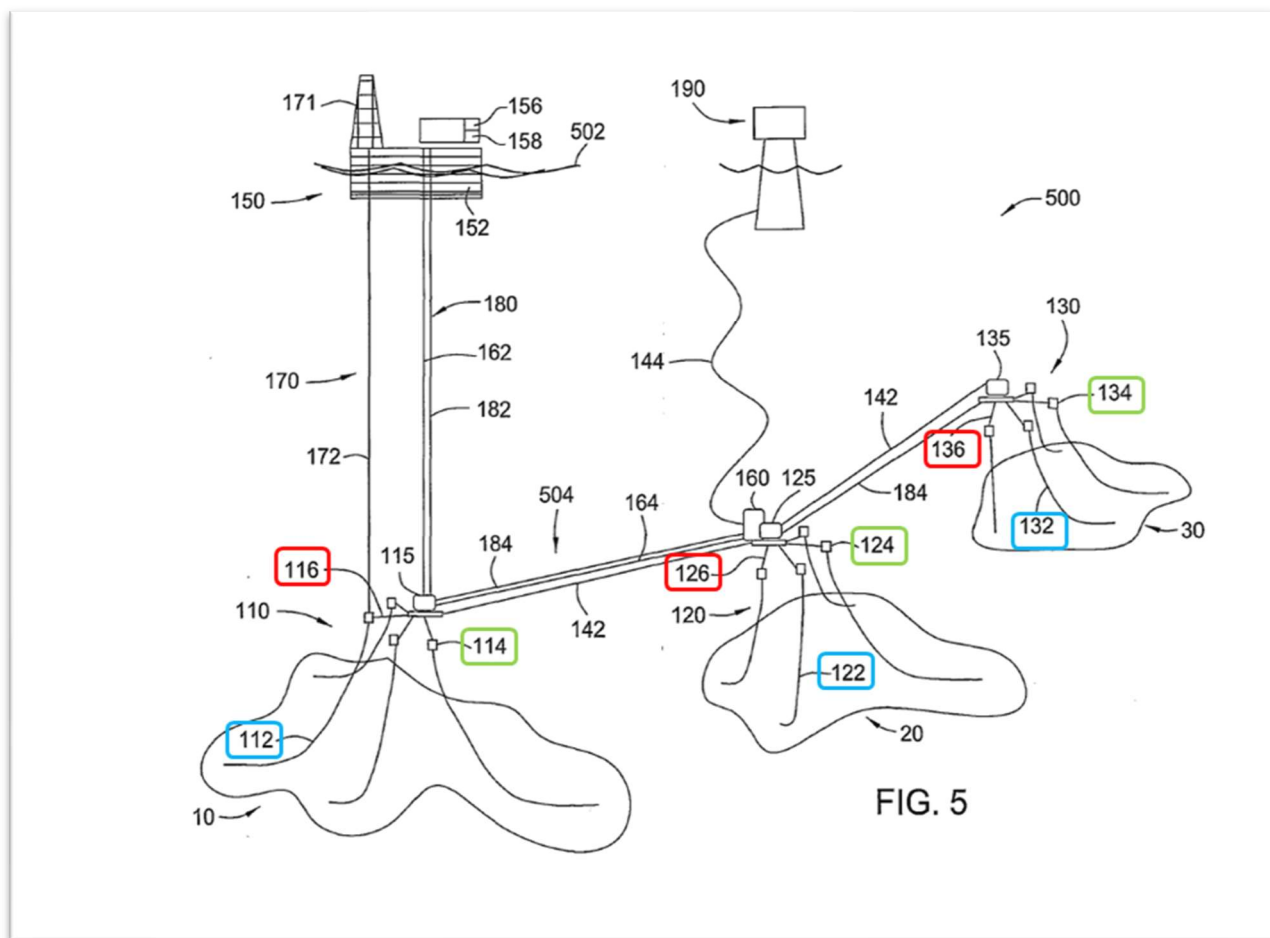
quoted correctly. For example, *Crossley* teaches “It is also understood that one or more strings of production tubing are provided in the wellbore of each well 112, 122, 132 to provide a flowpath for production fluids *to the wellhead*.”¹⁵¹

184. When Dr. Nikolaou quoted this section, he replaced “to the wellhead” with “from the wellhead,” and then went on to state, with only this misquote as support, “[f]low paths, including strings of production tubing, (i.e., “connections,” including a “third connection”) through flow line jumpers for each well all terminate at the respective collection manifold for each wellsite. Flow paths, including strings of production tubing, (i.e., “connections,” including a “third connection”) through flow line jumpers for each well all terminate at the respective collection manifold for each wellsite.”¹⁵² However the teachings of *Crossley* do not support that the flow paths of the production tubing terminate at the manifold, rather that the flow paths terminate at the wellhead (to the wellhead). The “flow line jumpers” that Dr. Nikolaou and Petitioner refer to are separate structures from the “production tubing” or “production lining.” These flow line jumpers are limited, according to *Crossley*, to one per well. *Crossley* teaches “[e]ach well 112, 122, 132 has a flow line jumper 116, 126, 136 extending from the trees 114, 124, 134 in order to transport production

¹⁵¹ Ex. 1005 at [0044] (emphasis added).

¹⁵² Ex. 1003 at ¶ 157.

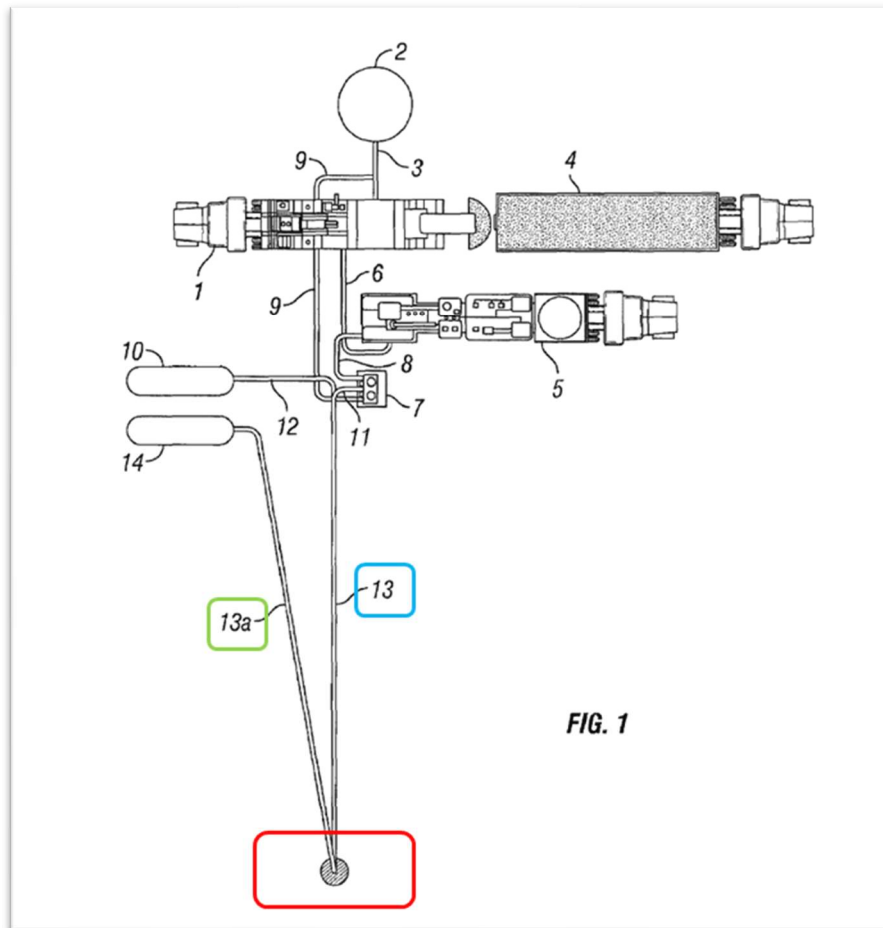
or injection fluids.”¹⁵³ Further, the presence of a single “flow line jumper” (116, 126, 126, annotated in red) from each well (112, 122, 132 annotated in blue) and wellhead (114, 124, 134 annotated in green) to the manifold (115, 125, 135 annotated in magenta) is clear in Fig. 5 of *Crossley*, duplicated and annotated below.



185. Similarly, *Albers* only shows one connection (13, annotated in blue) between the manifold (not shown) and the well (annotated in red). The second

¹⁵³ Ex 1005 at [0045].

connection at the well (13a annotated in green) does not go to the manifold, but rather to a second nitrogen / carbon dioxide tank.



186. Accordingly, there is no support in either *Crossley* or *Albers* for a third connection between the manifold and the first well, as there is only one connection for each well in *Crossley* and similarly only one connection between the manifold and the well in *Albers*. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 16.

17. Dependent Claim 17

187. Dependent Claim 17 requires that “the third connection is operable to deliver a fluid from the first well to the manifold.” Dependent Claim 17 depends from Claim 16, which further depends from Claims 1 - 2, and contains all the limitations of Claims 1, 2, and 16. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1, 2, and 16. Furthermore, as discussed above, there is simply no disclosure, teaching, or suggestion in *Crossley* or *Albers* of a “third connection” between the first well and the manifold, and therefore, there is no “third connection” that could be “operable to deliver a fluid from the first well to the manifold.” Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, suggest the limitations of Claim 17.

18. Dependent Claim 18

188. Dependent Claim 18 requires “a fourth connection between the manifold and the second well.” Dependent Claim 18 depends from Claim 17, which further depends from Claims 1, 2, and 16, and contains all the limitations of Claims 1, 2, 16, and 17. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1, 2, 16, and 17.

189. Further, similar to the discussion above regarding the “third connection” between the first well and the manifold, there is no disclosure teaching, or suggestion in either *Crossley* or *Albers* that there is a fourth connection between

the second well and the manifold. Again, Dr. Nikolaou and the Petition rely on the “strings of production [tubing, *sic.*]” to show the “fourth connection.” As discussed above regarding Claim 16, the strings of tubing flow *to the wellhead* and not *from the wellhead* to the manifold as Dr. Nikolaou suggests by misquoting *Crossley*. As further discussed above regarding Claim 16, there is only one connection between each well and the manifold in both *Crossley* and *Albers*. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 18.

19. Dependent Claim 19

190. Dependent Claim 19 requires that “the fourth connection is operable to deliver a fluid from the second well to the manifold.” Dependent Claim 19 depends from Claim 18, which further depends from Claims 1, 2, 16, and 17, and contains all the limitations of Claim 1, 2, and 16-18. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claims 1, 2, and 16-18. Furthermore, as discussed above, there is simply no disclosure, teaching, or suggestion in *Crosley* or *Albers* of a “fourth connection” between the second well and the manifold, and therefore, there is no “fourth connection” that could be “operable to deliver a fluid from the second well to the manifold.” Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 19.

20. Dependent Claim 20

191. Dependent Claim 20 depends from Claim 1, and contains all the limitations of Claim 1. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 1.

192. Further, the Petition's and Dr. Nikolaou's assertion that it would have been obvious to have the collection manifolds located on the boat ignores *Crossley*'s teachings. In particular, *Crossley* teaches the use of the subsea collection manifolds enables "production fluids from a well-site [to] be commingled for unitary transportation to another location (such as a gathering facility seen at 190 in Figure 5)."¹⁵⁴ In the embodiment relied on by the Petition and Dr. Nikolaou, *Crossley* discloses a single unitary transport line from manifolds 115 and 125 to the surface.¹⁵⁵ Relocating *Crossley*'s subsea collection manifolds to the surface on a boat would be contrary to this teaching of *Crossley* because it would eliminate the unitary transport line to the surface as each well would require its own individual flowline from the wellhead to the collection manifold on the surface.

193. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 20.

¹⁵⁴ Ex. 1005 at [0045].

¹⁵⁵ Ex. 1005 at Fig. 1 (element 144), [0046] ("In this manner, the first 115 and second 125 collection manifolds actually share a single export flow line 144.").

21. Dependent Claim 21

194. Dependent Claim 21 depends from Claim 1 and contains all the limitations of Claim 1. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 1. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 21.

22. Dependent Claim 22

195. Dependent Claim 22 depends from Claim 1 and contains all the limitations of Claim 1. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 1. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest the limitations of Claim 22.

23. Dependent Claim 23

196. Dependent Claim 23 depends from Claim 1 and contains all the limitations of Claim 1. As described above, the combination of *Crossley* and *Albers* fails to disclose, teach, or suggest all limitations of Claim 1. Accordingly, the combination of *Crossley* and *Albers* fails to disclose, teach, suggest the limitations of Claim 23.

24. Independent Claim 24

197. Claim 24 contains the following limitations.

[24pre] A system for centralized well operations comprising:

[24a] a well treatment operations factory which manufactures and pumps a well stimulation fluid;

[24b] a first connection between a first pad and the well operations factory, wherein the first pad has a first well;

[24c] a second connection between a second pad and the well operations factory, wherein the second pad has a second well; and

[24d] means for simultaneously flowing: a first stimulation fluid to the first pad and not to the second pad; and a second stimulation fluid to the second pad and not to the first pad;

[24e] wherein the first stimulation fluid and the second stimulation fluid have different compositions.

198. Dr. Nikolaou and Petitioner perform no additional analysis of this claim other than that already discussed regarding Claim 1. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest all limitations of Claim 24 for the same reasons as those discussed above regarding Claim 1.

25. Independent Claim 25

199. Claim 25 contains the following limitations.

[24pre] A system for centralized well operations comprising:

[25a] a well treatment operations factory which dynamically manufactures and pumps a well stimulation fluid;

[25b] a first connection between a first well and the well operations factory;

[25c] a second connection between a second well and the well operations factory; and

[25d] means for simultaneously flowing: a first stimulation fluid to the first well and not to the second well; and a second stimulation fluid to the second well and not to the first well;

[25e] wherein the first stimulation fluid and the second stimulation fluid have different compositionse.

200. Dr. Nikolaou and Petitioner perform no additional analysis of this claim other than that already discussed regarding Claim 1. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest all limitations of Claim 25 for the same reasons as those discussed above regarding Claim 1.

26. Independent Claim 26

201. Claim 26 contains the following limitations.

[26pre] A system for centralized well operations comprising:

[26a] a well treatment operations factory which manufactures and pumps a well stimulation fluid;

[26b] a first connection between a first plurality of wells and the well operations factory;

[26c] a second connection between a second plurality of wells and the well operations factory; and

[26d] means for simultaneously flowing: a first stimulation fluid to the first plurality of wells and not to the second plurality of wells; and a second stimulation fluid to the second plurality of wells and not to the first plurality of wells;

[26e] wherein the first stimulation fluid and the second stimulation fluid have different compositions.

202. Dr. Nikolaou and Petitioner perform no additional analysis of this claim other than that already discussed regarding Claim 1. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest all limitations of Claim 26 for the same reasons as those discussed above regarding Claim 1.

27. Independent Claim 27

203. Claim 27 contains the following limitations.

[27pre] A system for centralized well operations comprising:

[27a] a well treatment operations factory capable of manufacturing and simultaneously pumping a plurality of well stimulation fluids;

[27b] a first connection between a first well and the well operations factory;

[27c] a second connection between a second well and the well operations factory; and

[27d] means for simultaneously flowing: a first stimulation fluid to the first well and not to the second well; and a second stimulation fluid to the second well and not to the first well.

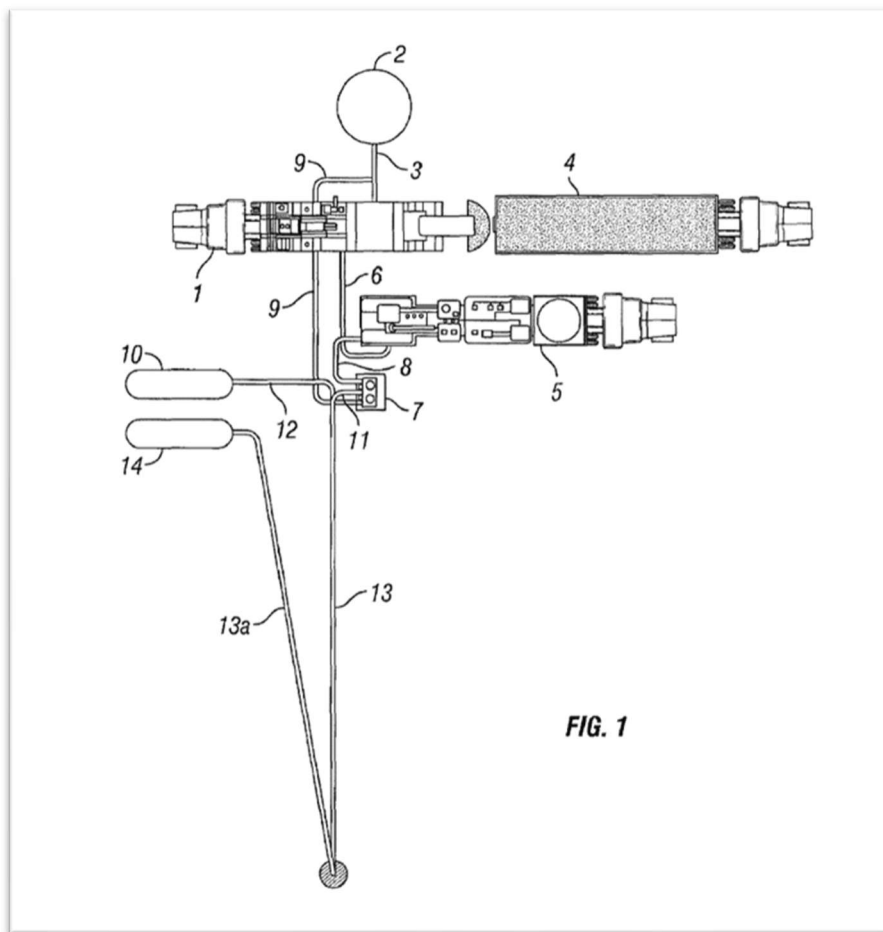
204. Dr. Nikolaou and Petitioner perform no additional analysis of this claim other than that already discussed regarding Claim 1. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest all limitations of Claim 27 for the same reasons as those discussed above regarding Claim 1.

205. Additionally, this claim requires that the two different well stimulation fluids (first stimulation fluid and second stimulation fluid) be manufactured and pumped simultaneously. Dr. Nikolaou relies on a disclosure in *Albers* that fluid composition can be changed based on the requirements of different formations. However, Claim 27 requires more than just changing fluid composition based on different formations, it requires that the different fluids be manufactured and pumped to the two different wells simultaneously.

206. As discussed regarding Claim 1, the system of *Albers* makes no mention of manufacturing or pumping different fluids simultaneously. For example, *Albers* describes the manufacture of its well stimulation fluid as follows:¹⁵⁶

The sand trailer (4) typically includes one or more proppant containers (not shown), which are used to transfer proppant to the mixing tub (not shown) of the blender unit (1). The blender unit (1) is shown further connected to a conventional high-pressure pump (5) by a second conduit (6). The high pressure pump (5) is in turn connected to a conventional sand intensifier unit (7) by a third conduit (8). The sand intensifier unit (7) is then connected back to the first conduit (3), and subsequently the fluid storage device (2), via a reflux conduit (9). A first nitrogen/carbon dioxide storage tank and pump (10) is schematically shown connected to a short conduit (11) extending from the sand intensifier unit (7). The first nitrogen/carbon dioxide storage tank and pump (10) is connected to the short conduit (11) via a fourth conduit (12). Those connections are then attached to a manifold connection (not shown), which is in turn connected to a first wellhead conduit (13) that extends directly to the wellhead.

¹⁵⁶ Ex. 1006 at 3:61-4:11.



207. The system of *Albers* only contains one blending system (blender, manifold, conduits etc.) and would be incapable of manufacturing two different well stimulation fluids simultaneously. The different fluid compositions of *Albers* are manufactured for different formations over time and space, and not manufactured or flowed simultaneously.¹⁵⁷ There is no suggestion that the system of *Albers*, even in combination with *Crossley*, would be configured to either manufacture different fluids simultaneously, or flow the fluids simultaneously to different wells.

¹⁵⁷ See, e.g., Ex. 1006 at Fig. 6, Fig. 8, 6:64-7:26.

208. Accordingly, the combination of *Crossley* and *Albers* does not disclose, teach or suggest the limitations of 27.

XII. GROUND 2: LEHMAN DOES NOT CURE THE FAILURES OF CROSSLEY AND ALBERS FOR DEPENDENT CLAIMS 11 AND 13

209. The Petition points to *Lehman* as allegedly teaching portions of Claims 11 and 13 that are missing from the combination of *Crossley* and *Albers*. More specifically, the Petition points to *Lehman* as teaching “a flowback and reuse system,” which the Petition claims would have been an obvious addition to the system of *Crossley* and *Albers*. However, as discussed below, Claims 11 and 13 do not simply require “a flowback and reuse system,”¹⁵⁸ which was known at the time of the ‘394 Patent, but a specific configuration and use of equipment, including manifolds, which is missing from *Crossley*, *Albers* and *Lehman* as well. Further, the Petition points to no portion of claimed prior art that suggests the specific configuration, nor does the Petition or Dr. Nikolaou provide any rationale why it would have been obvious to modify the system of *Crossley* to provide the specific configuration of the ‘394 Patent. The Petition instead points to the additional limitations of Claims 11 and 13 in isolation and does not address the Claim as a whole.

¹⁵⁸ Petition at 63.

210. As discussed above for Claims 11 and 13, the combination of *Crossley* and *Albers* fail to disclose, teach, or suggest delivery of different stimulation fluids to two different wells simultaneously using the same manifold and the delivery of a stimulation fluid from the well back to the same manifold. *Lehman* also does not disclose, teach, or suggest this. *Lehman* teaches the conditioning and use of “used” stimulation fluid, and more particularly, water-based and foam-based stimulation fluids. However, when *Lehman* discusses manifolds, those are not manifolds used to connect to the well (for either delivery or receipt of stimulation fluid), but rather are manifolds used to connect multiple tanks of the same input to the blender (i.e., used polymer, new polymer concentrate, and fresh water).¹⁵⁹ Accordingly, the addition of *Lehman* does nothing to “fill in” the missing pieces of *Crossley* and *Albers*. As a result, the combination of *Crossley*, *Albers*, and *Lehman* does not disclose, teach or suggest all limitations of Claims 11 and 13 in their entirety.

211. Furthermore, *Lehman* teaches that its flowback and reuse system may be used with traditional water-based fracturing fluids or foam-based fracturing fluids.¹⁶⁰ However, *Albers* distinguishes the traditional water-based fracturing fluids or foam-based fracturing fluids of *Lehman* from its own gaseous nitrogen fracture-

¹⁵⁹ See, e.g. Ex 1009 at Fig 3, [0055].

¹⁶⁰ Ex. 1009 at [0059], [0079].

stimulation fluids.¹⁶¹ More specifically, *Albers*'s "Background of the Invention" describes "[o]ne of the most widely used methods involves the hydraulic fracturing of low permeability formations *using one of a variety of water-containing fracturing fluids* intermixed with proppants such as sand, glass beads, and the like."¹⁶² It further describes "[a]nother prior art technique for stimulating reservoirs involves the hydraulic fracturing of low permeability formations *using foam*."¹⁶³ It then explains that "[a] more recent development in well fracturing involves the use of gaseous nitrogen alone as a fracturing agent" and that, "[a]lthough gaseous nitrogen fracturing has many advantages over traditional water-based and foam fracturing techniques, there exists a need for a gaseous nitrogen fracturing technique that includes simultaneous placement of an effective amount of proppant within the fractured formation surrounding the well bore."¹⁶⁴ Because *Albers* distinguishes its fracturing fluid that the Petition proposes to flow using *Crossley*'s production system from the fracturing fluids suitable for *Lehman*'s flowback and reuse system, the

¹⁶¹ Ex. 1006 at 1:6-61.

¹⁶² Ex. 1006 at 1:7-12.

¹⁶³ Ex. 1006 at 1:22-24.

¹⁶⁴ Ex. 1006 at 1:38-39, 52-57.

Petition has not established that a POSITA would have been motivated by *Lehman* to flow back *Albers*'s fracture-stimulation fluid.

XIII. CONCLUSION

212. All statements made herein of my own knowledge are true, and all statements made on information and belief are believed to be true. I further understand that willful false statements and the like are punishable by fine or imprisonment, or both under Section 1001 of Title 18 of the United States Code. I declare under penalty of perjury that the foregoing is true and correct.

Date: July 11, 2024



Robert A. Durham