Andres Mendez Ruiz
Department of Economics
University of Texas at Austin
Email: andres.mendez@utexas.edu
Cell: 1-512-783-8614
andresmendezruiz.com
Mexican Citizenship

December 1, 2019

Members of the Search Committee
Department of Agricultural Economics
Texas A&M University
College Station, Texas

Dear Members of the Search Committee:

I am applying for the Assistant Professor of Agricultural Marketing and Quantitative Analysis position as advertised in the JOE Listings. I am a PhD in Economics Candidate at the University of Texas at Austin, and I would like to be considered in your recruitment process.

My primary area of research combines industrial organization with energy and environmental economics. I am motivated by the challenge of developing empirical models that accurately capture the essential institutional details of an industry to answer specific policy questions with the available data. This has led to my job market paper in which I investigate strategic cooperation for the collective provision of natural gas gathering infrastructure by oil and gas producers. I have included a copy of my job market paper entitled *Coase on Fire: Regulation and the Adoption of Natural Gas Flaring Abatement Technology in North Dakota*.

My interests match the job description of Texas A&M University very well, as I do research in applied microeconomics. My primary field of research is industrial organization. Moreover, I was a teaching assistant for a variety of industrial organization, econometrics, and microeconomics classes. I am very motivated in teaching undergraduate and graduate courses in industrial organization, econometrics, energy and environmental economics, and microeconomics.

I will be attending the American Economic Association annual meeting in San Diego and I am available for interviews on all days from January 2-5, 2020. Thank you very much for your consideration and I look forward to hearing back from you.

Sincerely,

Andres Mendez Ruiz

ANDRÉS MÉNDEZ RUIZ

University of Texas at Austin
Department of Economics
2225 Speedway C3100
Austin, TX 78712

cell: 512-783-8614
andres.mendez@utexas.edu
andresmendezruiz.com

EDUCATION

Ph.D. Candidate, Economics, University of Texas at Austin, May 2020 (Expected)
Dissertation Title: *"Essays on Inter-firm Contracting"*
M.S., Economics, University of Texas at Austin, 2017
M.S., Econometrics, University of Amsterdam, 2014
M.S., Economics, El Colegio de México, 2012
B.A., Philosophy, Universidad de Guadalajara, 2009

REFERENCES

Daniel Ackerberg (Co-Chair)
Department of Economics
University of Texas at Austin
512-475-9538
daniel.ackergberg@gmail.com

Eugenio Miravete (Co-Chair)
Department of Economics
University of Texas at Austin
512-232-1718
eugenio@eugeniomiravete.com

Sheila Olmstead
LBJ School of Public Affairs
University of Texas at Austin
512-471-2064
sheila.olmstead@austin.utexas.edu

Jorge Balat
Department of Economics
University of Texas at Austin
512-475-7353
jbalat@utexas.edu

TEACHING AND RESEARCH FIELDS

Fields: Industrial Organization, Econometrics
Sub-Fields: Energy and Environmental Economics

HONORS, SCHOLARSHIPS, AND FELLOWSHIPS

2019 – 2020	Adam Smith Fellowship, Mercatus Center
2019 – 2020	Human Studies Fellowship, Institute for Humane Studies
Summer, 2019	PERC Graduate Fellowship, Property and Environment Research Center
2014 – 2019	CONACYT Doctoral Scholarship, Mexico's National Council of Science and Technology
2014 – 2015	Supplementary Doctoral Scholarship, Mexican Secretariat of Public Education
2013 – 2014	Amsterdam Merit Scholarship, University of Amsterdam
Fall, 2011	Excelencia Colmex Award, El Colegio de México
Fall, 2010	Excelencia Colmex Award, El Colegio de México
2010 – 2012	CONACTY Master's Degree Scholarship, Mexico's National Council of Science and Technology

RESEARCH EXPERIENCE AND OTHER EMPLOYMENT

2018 – 2019	University of Texas at Austin, Energy Institute, Research Assistant for Professor Carey King

2017 – 2018	University of Texas at Austin, Department of Economics, Research Assistant for Professor Jorge Balat
2012 – 2013	Mexican Federal Competition Commission, Assistant Manager at the General Division for Planning and Evaluation
Summer, 2011	Human Development Report Office, United Nations Development Programme, Research Intern

TEACHING EXPERIENCE

Fall, 2019	Structural Econometrics, University of Texas at Austin, Teaching Assistant for Professor Daniel Ackerberg
2017-2018	Industrial Organization, University of Texas at Austin, Teaching Assistant for Professors David S. Sibley and Eugenio Miravete
Fall, 2016	Introduction to Econometrics, University of Texas at Austin, Teaching Assistant for Professor Stephen Trejo
Fall, 2014	Applied Industrial Organization and Network Economics, University of Texas at Austin, Teaching Assistant for Professor Neil Gandal

PROFESSIONAL ACTIVITIES

July, 2019	The Bakken Conference and Expo
February. 2019	UT Energy Week 2019, The University of Texas at Austin
July, 2018	Jerusalem Summer School of Economics, Hebrew University of Jerusalem
October, 2018	Fifth Annual Conference on Transportation, Economics, Energy and the Environment (TE3), University of Michigan
Winter, 2012	Antitrust Workshop, Universidad Iberoamericana, Mexican Federal Competition Commission and International Chamber of Commerce

WORKING PAPERS

"Coase on Fire: Regulation and the Adoption of Natural Gas Flaring Abatement Technology in North Dakota" (*Job Market Paper*)

Unconventional fossil fuel extraction technology and favorable market conditions ignited an oil production boom in North Dakota. At its onset, around 2008, the state lacked enough pipeline infrastructure to capture all the associated natural gas extracted jointly with oil, resulting in large volumes of flared natural gas. Against this backdrop, I investigate the role of contracting costs in hindering firm cooperation in constructing pipelines, thus preventing firms from fully harnessing available mutual economies of scale. To do so, I model firms' well-connection decisions as a static complete information game in which producers decide what fraction of their wells to connect, while considering the effect of externalities from other producers' actions on their own connection costs. I measure the extent of inter-firm contracting costs with respect to a benchmark case in which all wells are owned by a single firm, and as such, inter-firm contracting costs are assumed to be zero. I also use my model to study what the investment outcome would be if contracting was costless in that sense. Finally, I compute a counterfactual to determine what flaring penalty would result in market-level outcomes mimicking those of a single firm.

OTHER

Languages: English (fluent), French (intermediate), German (fluent), and Spanish (native)

THE UNIVERSITY OF TEXAS AT AUSTIN

OFFICE OF THE REGISTRAR, MAIN BLDG. ROOM 1, AUSTIN, TX 78712-1157, (512) 475-7575

FICE CODE: 3658 IPEDS CODE: 228778 ATP CODE: 6882 ACT CODE: 4240

OFFICIAL TRANSCRIPT

NAME: MENDEZ RUIZ, ANDRES STUDENT ID: XXX-XX-1663 DATE: 10/25/19
DOB: 12/03/83 PAGE: 1

DEGREES AWARDED BY THE UNIVERSITY OF TEXAS AT AUSTIN:

DEGREE: MASTER OF SCIENCE IN ECONOMICS
DATE: MAY 20, 2017
MAJOR: ECONOMICS

ATTENDED: UNIVERSIDAD DE GUADALAJARA SPRING 2005 SPRING 2009
DEGREE AWARDED: LICENCIADO EN FILOSO FALL 2009

ATTENDED: EL COLEGIO DE MEXICO FALL 2010 SPRING 2012
DEGREE AWARDED: M S ECON SUMMER 2012

ATTENDED: UNIVERSITY OF AMSTERDAM FALL 2013 SUMMER 2014
DEGREE AWARDED: M S SUMMER 2014

COURSEWORK UNDERTAKEN AT THE UNIVERSITY OF TEXAS AT AUSTIN

FALL SEMESTER 2014 GRADUATE SCHOOL
ECO 387L 1-MICROECONOMICS I 3.0 B+
ECO 387L 2-MACROECONOMICS I 3.0 B+
ECO 392M 8-MATH FOR ECONOMISTS I 3.0 A
HRS UNDERTAKEN 9 HRS PASSED 9 GPA HRS 9 GR PTS 31.98 GPA 3.5533

SPRING SEMESTER 2015 GRADUATE SCHOOL
ECO 387L 3-MICROECONOMICS II 3.0 A
ECO 387L 4-MACROECONOMICS II 3.0 B+
ECO 392M 2-ECONOMETRICS I 3.0 A
HRS UNDERTAKEN 9 HRS PASSED 9 GPA HRS 9 GR PTS 33.99 GPA 3.7766

SUMMER SEMESTER 2015 GRADUATE SCHOOL
ECO F387L 30-RESEARCH SEMINAR 3.0 CR
HRS UNDERTAKEN 3 HRS PASSED 3 GPA HRS 0 GR PTS 0.00 GPA 0.0000

FALL SEMESTER 2015 GRADUATE SCHOOL
ECO 388D ECONOMETRICS II 3.0 A
HRS UNDERTAKEN 3 HRS PASSED 3 GPA HRS 3 GR PTS 12.00 GPA 4.0000

SPRING SEMESTER 2016 GRADUATE SCHOOL
ECO 388E 1-ADV ECONOMETRIC THEORY I 3.0 A
HRS UNDERTAKEN 3 HRS PASSED 3 GPA HRS 3 GR PTS 12.00 GPA 4.0000

FALL SEMESTER 2016 GRADUATE SCHOOL
ECO 384K INDUSTRIAL ORGANIZATION 3.0 A
ECO 385K 1-INTRO TO LABOR ECONOMICS 3.0 A-
ECO 388E 2-ADV ECONOMETRIC THEORY II 3.0 A
CSE 384K THEORY OF PROBABILITY 3.0 A
HRS UNDERTAKEN 12 HRS PASSED 12 GPA HRS 12 GR PTS 47.01 GPA 3.9175

SPRING SEMESTER 2017 GRADUATE SCHOOL
M E 382Q 4-ENERGY TECHNOLOGY AND POLICY 3.0 B+
ECO 384K EMPIRICAL INDUSTRIAL ORGANIZTN 3.0 A-
ECO 386E HEALTH ECONOMICS 3.0 A

MORE WORK ON NEXT PAGE

Mark Simpson, University Registrar

*** ISSUED TO STUDENT ***

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OFFICIAL TRANSCRIPT

NAME: MENDEZ RUIZ, ANDRES   STUDENT ID: XXX-XX-1663   DATE: 10/25/19
DOB: 12/03/83

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CONTINUE  SPRING SEMESTER 2017      GRADUATE SCHOOL
          HRS UNDERTAKEN 9    HRS PASSED 9    GPA HRS 9    GR PTS   33.00   GPA 3.6666

          SUMMER SEMESTER 2017      GRADUATE SCHOOL
               ECO F386E  SEMINAR IN ADV MICROECONOMICS                    3.0  A
          HRS UNDERTAKEN 3    HRS PASSED 3    GPA HRS 3    GR PTS   12.00   GPA 4.0000

          FALL SEMESTER 2017        GRADUATE SCHOOL
               ECO  386E  RESEARCH SEMINAR: ADV MICRO                      3.0  A
               ECO  387M  WRITING SEMINAR IN ECONOMICS                     3.0  A
               ECO  388E  STRUCTURAL ECONOMETRICS                          3.0  A
          HRS UNDERTAKEN 9    HRS PASSED 9    GPA HRS 9    GR PTS   36.00   GPA 4.0000

          SPRING SEMESTER 2018      GRADUATE SCHOOL
               ECO  387M  WRITING SEMINAR IN ECONOMICS                     3.0  A
               ECO  388E  RESEARCH SEMINAR: ADV METRICS                    3.0  A
               P A  388K  ENVIRON & ENERGY ECONOMICS                       3.0  A
          HRS UNDERTAKEN 9    HRS PASSED 9    GPA HRS 9    GR PTS   36.00   GPA 4.0000

          SUMMER SEMESTER 2018      GRADUATE SCHOOL
               ECO F386E  RESEARCH SEMINAR: ADV MICRO                      3.0  A
          HRS UNDERTAKEN 3    HRS PASSED 3    GPA HRS 3    GR PTS   12.00   GPA 4.0000

          FALL SEMESTER 2018        GRADUATE SCHOOL
               ECO  387M  WRITING SEMINAR IN ECONOMICS                     3.0  A
               ECO  388E  RESEARCH SEMINAR: ADV METRICS                    3.0  A
               ESL  389S  ADVANCED ORAL COMMUNICATION                      3.0  CR
          HRS UNDERTAKEN 9    HRS PASSED 9    GPA HRS 6    GR PTS   24.00   GPA 4.0000

          SPRING SEMESTER 2019      GRADUATE SCHOOL
               ECO  386E  RESEARCH SEMINAR: ADV MICRO                      3.0  A
               ECO  387E  RESEARCH SEMINAR: ADV MACRO                      3.0  A
               ECO  387M  WRITING SEMINAR IN ECONOMICS                     3.0  A
          HRS UNDERTAKEN 9    HRS PASSED 9    GPA HRS 9    GR PTS   36.00   GPA 4.0000

                  CUMULATIVE TOTALS EARNED AS A GRADUATE STUDENT AT U.T. AUSTIN
          HRS UNDERTAKEN 90   HRS PASSED 90   GPA HRS 84   GR PTS  325.98   GPA 3.8807

          THIS TRANSCRIPT IS BEING ISSUED PRIOR TO THE END OF THE SEMESTER.
          COURSES LISTED BELOW ARE IN PROGRESS.  ANY GRADES THAT APPEAR ARE
          NOT INCLUDED IN COMPUTATION OF THE GRADE POINT AVERAGE OR
          SCHOLASTIC STATUS.  A POUND SIGN INDICATES NO FINAL GRADE HAS
          BEEN ASSIGNED.

          FALL SEMESTER 2019        GRADUATE SCHOOL
               ECO  380   RESEARCH COURSE                                  3.0  #
               ECO  380   RESEARCH COURSE                                  3.0  #
               ECO  387M  WRITING SEMINAR IN ECONOMICS                     3.0  #

                     ***  E N D   O F   T R A N S C R I P T  ***
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MORE WORK ON NEXT PAGE

Mark Simpson, University Registrar

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THE UNIVERSITY OF TEXAS AT AUSTIN

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FICE CODE: 3658 IPEDS CODE: 228778 ATP CODE: 6882 ACT CODE: 4240

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NAME: MENDEZ RUIZ, ANDRES STUDENT ID: XXX-XX-1663 DATE: 10/25/19
DOB: 12/03/83 PAGE: 3

TSI STATUS INFORMATION

TSI AREA	TSI STATUS	EXPLANATION
ALL	EXEMPT	DEGREE HOLDER

TEC 51.907 UNDERGRADUATE COURSE DROP COUNTER: X

Mark Simpson, University Registrar

*** ISSUED TO STUDENT ***

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THE UNIVERSITY OF TEXAS AT AUSTIN
Office of the Registrar

SEMESTERS, SESSIONS, AND TERMS: An academic year consists of consecutive fall and spring semesters and the following summer session. A semester normally is about sixteen weeks long. The summer session comprises a first term (f) and a second term (s) each six weeks in duration; work also is offered on a nine-week basis (n) and a whole-session or twelve-week basis (w). The same academic credit is given for a course whether it is taken in the long session or the summer session.

ACADEMIC CREDIT: The unit of measure for academic credit is the semester hour. Most courses meet three hours a week in the long-session semester and have a credit value of three semester hours. The same courses meet for seven and one-half hours a week in a six-week summer term and have a credit value of three semester hours. For students enrolled in graduate programs, GPA hours and hours-passed reflect only those graduate-level courses (excluding thesis, dissertation, report, and treatise) and certain in-residence upper-division undergraduate courses taken while the student was enrolled in the Graduate School. Upper-division undergraduate courses taken in the fall of 1999 through the summer session of 2008 are not included.

COURSE NUMBERING SYSTEM: Courses are designated by a three-digit number or a three-digit number with a capital letter affixed. The first digit in the course number indicates the value of the course: 001-099 indicates zero credit value; 101-199 indicates one semester hour credit; 201-299 indicates two semester hours credit; 301-399 indicates three semester hours credit; and so on. The last two digits indicate the rank of the course: 01-19 indicates lower-division rank; 20-79 indicates upper-division rank; and 80-99 indicates graduate rank.

All courses in the School of Law and some courses in the College of Pharmacy are considered professional rank.

Two courses with the same abbreviation and the same last two digits may not both be counted for credit by a student unless the two digits are followed by a capital letter. Some courses may be repeated for credit. Those courses are indicated in the University's catalogs.

PREFIXES AND SUFFIXES: The suffix letters A, B, and X, Y, Z indicate that a part of the course was given. A suffix of A or B divides the course into two parts; X, Y, or Z divides the course into three parts. In each case, the semester-hour credit given for the course is reduced accordingly.

The prefix letters f, s, n, and w indicate the terms of the summer session (see above) in which the course was offered: f indicates first term; s indicates second term; n indicates nine-week session; and w indicates whole session.

For grading systems used prior to 1979, contact the Office of the Registrar.

GRADE		GRADE PTS PER SEM HR
	1979-1980 through 2004-2005	
A	EXCELLENT	4
B	ABOVE AVERAGE	3
C	AVERAGE	2
D	PASS	1
F	FAILURE	0
I	PERMANENT INCOMPLETE (effective fall 1997)	na[1]
X	TEMPORARY DELAY OF FINAL COURSE GRADE	na[1]
CR	CREDIT	na[1]
NC	NO CREDIT	na[1]
*	COURSE IS CONTINUING	na[1]
Q	OFFICIALLY DROPPED THE COURSE	na[1]
W	OFFICIALLY WITHDREW FROM THE UNIVERSITY	na[1]
#	COURSE GRADE NOT REPORTED BY FACULTY	na[1]
S	SATISFACTORY (DEV courses only)	na[1]
U	UNSATISFACTORY (DEV courses only)	na[1]
	2005-2006 to the present	
A	EXCELLENT[3]	4.00
A-		3.67
B+		3.33
B	ABOVE AVERAGE[3]	3.00
B-		2.67
C+		2.33
C	AVERAGE[3]	2.00
C-		1.67
D+		1.33
D		1.00
D-	PASS[3]	0.67
F	FAILURE[3]	0.00
I	PERMANENT INCOMPLETE	na[1]
X	TEMPORARY DELAY OF FINAL COURSE GRADE	na[1]
CR	CREDIT	na[1]
NC	NO CREDIT	na[1]
*	COURSE IS CONTINUING	na[1]
Q	OFFICIALLY DROPPED THE COURSE	na[1]
W	OFFICIALLY WITHDREW FROM THE UNIVERSITY	na[1]
#	COURSE GRADE NOT REPORTED BY FACULTY	na[1]
S	SATISFACTORY (DEV courses only)	na[1]
U	UNSATISFACTORY (DEV courses only)	na[1]

Through the summer session of 2009, plus and minus grades are reserved for graduate, graduate business, and law students enrolled in graduate-level, non-law courses. Beginning fall of 2009, plus and minus grades are valid for all students.

A course dropped by the twelfth class day of a long-session semester (fourth class day of a summer session term) is not entered on the permanent academic record.
Prior to fall 1981, NC grades did not appear on the transcript.

SCHOOL OF LAW

Prior to 1990-1991

The School of Law employed a numeric grading system with the following alpha equivalents:

85 - 100	A
75 - 84	B
65 - 74	C
60 - 64	D
BELOW 60	F

1990-1991 - Present

Letter Grade	Grade Points Per Sem Hr. [2]
A+	4.3
A	4.0
A-	3.7
B+	3.3
B	3.0
B-	2.7
C+	2.3
C	2.0
D	1.7
F	1.3

1. na = not applicable to gpa calculation
2. Official grade point averages are not calculated for students in the School of Law.
3. Grade interpretation is applicable to undergraduate students.

NRTRP2 09/01/2009

DEPARTMENT OF ECONOMICS
THE UNIVERSITY OF TEXAS AT AUSTIN

2225 Speedway Stop C3100 • Austin, Texas 78712-1690 • (512) 471-3510
http://www.utexas.edu/cola/depts/economics

November 13, 2019

To whom it may concern,

It's my pleasure to write a recommendation letter for Andres Mendez Ruiz, who is finishing his Ph.D. in Economics at the University of Texas at Austin. I have known Andres for more than two years – since I moved to UT Austin from the University of Michigan. I am co-chair of his dissertation committee (along with Eugenio Miravete) and have closely observed his progress and presentations over the past 24 months. To preview, I think Andres is a smart, independent researcher working at the intersection of empirical industrial organization and natural resource/environmental economics. I think he would be a great hire for an economics department or other institution (e.g. School of Natural Resources or Policy School) looking for this type of economist and I think you should take a close look at him.

Andres' job market paper examines the economics behind the large amount of "flaring" of extracted natural gas in US fossil fuel production. Often wells that are drilled primarily to extract oil deposits also extract natural gas as a by-product. This is because fossil fuel deposits typically contain a mix of oil and gas. Since this natural gas is harder to bring to markets than oil, it is often simply burned off into the atmosphere right at the well-head – this is what is called "flaring". Not only does flaring waste potentially valuable BTUs of energy, but it also has negative environmental consequences due to the combustion involved in burning it.

Andres' work tries to understand why this is happening. A simple reason why this natural gas is "harder" to bring to markets is because it requires pipelines for efficient transport, and there is a large economy of scale in the construction of pipelines that would be required to transport the natural gas to markets. But there may be more economics to this story. In particular, in situations where wells in a given geographical area are owned by different firms, these economies of scale regarding pipeline building presumably work *across* firms. In other words, a pipeline serving firm A's wells in a given area presumably could also serve firm B's wells in a given area. But leveraging these economies of scale between different firms might not be simple. To do this, firm A and firm B would presumably need to contract/coordinate with one another, and this can be challenging due to the typical contracting problems we know in economics, e.g. asymmetric information, contracting costs, commitment problems, etc..

Andres starts by looking for reduced form evidence of the above effects. In particular, if what was described above is going on, one might expect the extent of flaring in a particular area to depend on market concentration in that area. In geographical locations where one firm owns all the wells, it might be easier to harness the economies of scale in transport than in geographical locations where ownership is more fragmented. Andres divides wells in western North Dakota into "markets" – intended to represent groups of wells who would likely benefit from returns to scale in transporting natural gas to processing plants (i.e. wells whose natural gas would likely end up in the same trunk pipeline if they were connected to processing plants). He then looks at flaring across these markets, assessing whether this depends on market concentration. The assumption here is that market concentration is exogenous to drivers of natural gas pipeline construction, which I think is plausible given that these wells were drilled primarily for oil rather than natural gas (moreover, one would expect a lot of state dependence in ownership given asymmetric information about reserves under a given well or field). Andres finds a strong relationship between market concentration and flaring – i.e. less concentrated markets have more flaring.

Andres next builds a model to more structurally interpret these relationships. This is a model of firms choosing whether to flare the natural gas coming out of each of their wells, or whether to connect those wells by pipeline to a processing plant. It is admittedly a stylized model. In particular, it ignores the dynamics of pipeline construction (who builds the main pipeline first, me, my competitor, or do we write a contract?) and the micro-level idiosyncracies of the exact geographic location of wells with respect to one another. But the model is already quite sophisticated and innovative. First, the modelling of the returns to scale is interesting – it includes a parameter that measures the extent to which returns to scale can be captured *across* firms (it is assumed that they can be fully captured within a single firm). Second, to simplify the "multi-unit" adoption game that firms play against each other (since each firm has to choose whether or not to connect multiple wells), Andres assumes the large number of wells in each market can be represented by a continuum. This latter simplification is what abstracting away from exact geographical locations of wells buys him – essentially he is assuming that all wells in a market are symmetrically geographically differentiated with respect to one another. This then dramatically simplifies a game with a combinatorial action space (which of my many wells I will connect) to a game where firms simply choose the *fraction* of their wells to connect.

Again, one could complain about this model being too stylized. But at least in my opinion it is exactly what it should be (at least for this paper) – the simplest structural model that can represent the empirical relationship between market concentration and flaring. It's also an elegant model that showcases Andres' modelling skills, something I think is extremely important for a successful career doing empirical work. In future work, Andres does plan to look at dynamics and micro level adoption decisions (e.g. looking at much smaller areas, considering exact locations of wells relative to each other and existing trunk lines), but that will be a very different (yet complementary) paper utilizing very different variation.

Andres estimates his structural model using data through 2014. The key finding is that if wells are owned by different firms, they are only able to achieve 59% of the cost synergies/economies of scale that would be achieved if those wells were owned by the same firm. This is an interesting finding, implying that some of the flaring is due to inability of fragmented markets to coordinate. Andres can also consider various counterfactual policies, e.g. consolidating well ownership, or taxing flaring (though for the latter to be valid one has to believe that the cost synergy parameter is structural). He is also in the process of estimating the same game using data after a set of regulations on flaring went into account at the end of 2014. This will be interesting, as it will shed light on whether these regulations were able to facilitate coordination amongst firms in pipeline building in fragmented markets. I think this is turning into a great paper on a really interesting topic. I would not be surprised if it eventually gets into a top journal like *RAND*.

More generally, I think Andres is an excellent candidate. He is thoughtful and diligent. In the past he has sometimes lacked some confidence, but I think this is greatly improving. Andres would be an excellent fit not only as an IO/Environmental/Natural Resource Economist in an economics department, but also in a School of Natural Resources or Policy School. He has experience in these latter environments - Sheila Olmstead, an environmental economist in the Policy School here at UT is on his dissertation committee, and he spent this past summer in Montana as a prestigious PERC (Property and Environment Research Center) graduate fellow interacting with environmental and natural resource economists as well as conservation experts.

In summary, I strongly support Andres' application for your position, and I hope you take a serious look at him. Please contact me if you have any questions (daniel.ackerberg@gmail.com).

Daniel A. Ackerberg
Addison Baker Duncan Centennial Professor of Economics

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Andres' work tries to understand why this is happening. A simple reason why this natural gas is "harder" to bring to markets is because it requires pipelines for efficient transport, and there is a large economy of scale in the construction of pipelines that would be required to transport the natural gas to markets. But there may be more economics to this story. In particular, in situations where wells in a given geographical area are owned by different firms, these economies of scale regarding pipeline building presumably work *across* firms. In other words, a pipeline serving firm A's wells in a given area presumably could also serve firm B's wells in a given area. But leveraging these economies of scale between different firms might not be simple. To do this, firm A and firm B would presumably need to contract/coordinate with one another, and this can be challenging due to the typical contracting problems we know in economics, e.g. asymmetric information, contracting costs, commitment problems, etc..

Andres starts by looking for reduced form evidence of the above effects. In particular, if what was described above is going on, one might expect the extent of flaring in a particular area to depend on market concentration in that area. In geographical locations where one firm owns all the wells, it might be easier to harness the economies of scale in transport than in geographical locations where ownership is more fragmented. Andres divides wells in western North Dakota into "markets" – intended to represent groups of wells who would likely benefit from returns to scale in transporting natural gas to processing plants (i.e. wells whose natural gas would likely end up in the same trunk pipeline if they were connected to processing plants). He then looks at flaring across these markets, assessing whether this depends on market concentration. The assumption here is that market concentration is exogenous to drivers of natural gas pipeline construction, which I think is plausible given that these wells were drilled primarily for oil rather than natural gas (moreover, one would expect a lot of state dependence in ownership given asymmetric information about reserves under a given well or field). Andres finds a strong relationship between market concentration and flaring – i.e. less concentrated markets have more flaring.

Andres next builds a model to more structurally interpret these relationships. This is a model of firms choosing whether to flare the natural gas coming out of each of their wells, or whether to connect those wells by pipeline to a processing plant. It is admittedly a stylized model. In particular, it ignores the dynamics of pipeline construction (who builds the main pipeline first, me, my competitor, or do we write a contract?) and the micro-level idiosyncracies of the exact geographic location of wells with respect to one another. But the model is already quite sophisticated and innovative. First, the modelling of the returns to scale is interesting – it includes a parameter that measures the extent to which returns to scale can be captured *across* firms (it is assumed that they can be fully captured within a single firm). Second, to simplify the "multi-unit" adoption game that firms play against each other (since each firm has to choose whether or not to connect multiple wells), Andres assumes the large number of wells in each market can be represented by a continuum. This latter simplification is what abstracting away from exact geographical locations of wells buys him – essentially he is assuming that all wells in a market are symmetrically geographically differentiated with respect to one another. This then dramatically simplifies a game with a combinatorial action space (which of my many wells I will connect) to a game where firms simply choose the *fraction* of their wells to connect.

Again, one could complain about this model being too stylized. But at least in my opinion it is exactly what it should be (at least for this paper) – the simplest structural model that can represent the empirical relationship between market concentration and flaring. It's also an elegant model that showcases Andres' modelling skills, something I think is extremely important for a successful career doing empirical work. In future work, Andres does plan to look at dynamics and micro level adoption decisions (e.g. looking at much smaller areas, considering exact locations of wells relative to each other and existing trunk lines), but that will be a very different (yet complementary) paper utilizing very different variation.

Andres estimates his structural model using data through 2014. The key finding is that if wells are owned by different firms, they are only able to achieve 59% of the cost synergies/economies of scale that would be achieved if those wells were owned by the same firm. This is an interesting finding, implying that some of the flaring is due to inability of fragmented markets to coordinate. Andres can also consider various counterfactual policies, e.g. consolidating well ownership, or taxing flaring (though for the latter to be valid one has to believe that the cost synergy parameter is structural). He is also in the process of estimating the same game using data after a set of regulations on flaring went into account at the end of 2014. This will be interesting, as it will shed light on whether these regulations were able to facilitate coordination amongst firms in pipeline building in fragmented markets. I think this is turning into a great paper on a really interesting topic. I would not be surprised if it eventually gets into a top journal like *RAND*.

More generally, I think Andres is an excellent candidate. He is thoughtful and diligent. In the past he has sometimes lacked some confidence, but I think this is greatly improving. Andres would be an excellent fit not only as an IO/Environmental/Natural Resource Economist in an economics department, but also in a School of Natural Resources or Policy School. He has experience in these latter environments - Sheila Olmstead, an environmental economist in the Policy School here at UT is on his dissertation committee, and he spent this past summer in Montana as a prestigious PERC (Property and Environment Research Center) graduate fellow interacting with environmental and natural resource economists as well as conservation experts.

In summary, I strongly support Andres' application for your position, and I hope you take a serious look at him. Please contact me if you have any questions (daniel.ackerberg@gmail.com).

Daniel A. Ackerberg
Addison Baker Duncan Centennial Professor of Economics

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<u>Letter of Recommendation for Andrés Méndez Ruiz.</u>

November 15, 2019

It is a great pleasure to write this letter of recommendation for Andrés Méndez. Andrés has interests in applied industrial organization, in general, and energy and environmental issues, in particular. Andrés has exceptionally strong quantitative skills and a promising potential as a researcher. I would place Andrés in the top 25% of graduate students I have encountered at UT and Johns Hopkins. I have known Andrés since I moved to UT in 2017 in several capacities: he sat in my grad IO class, he was my RA, and I have been advising him on his research.

In his dissertation research, Andrés addresses an old economic problem: the provision of quasi-public goods. He looks at this problem in the context of oil and gas producers in North Dakota. In particular, he looks at how these firms interact with each other to build the necessary infrastructure to gather the natural gas they produce and transport it to a gas processing plant. In this set up, there are two forces at play. On the one hand, there are external economies of scale (in that two firms building a shared pipeline face a lower cost than the sum of two individual pipelines) hence inducing firms to cooperate and, on the other hand, there are contracting (or transaction) costs that provide the opposite incentive.

The construction of gas gathering infrastructure is an important problem in that if the gas is not captured it has to be flared. On the one hand, this could represent an economic waste of resources and, on the other, the associated environmental consequences can be significant. In terms of the former, the extent to which flaring represents an economic waste would depend on the cost of building the infrastructure to capture the gas. Hence estimating these costs are a central point in Andrés research. To do so, Andrés models the firms' decisions to connect their wells to the natural gas gathering network as a static game of complete information. A key feature of the model is the well connection cost function. It allows for internal (to the firm) economies of scale, across-firm economies of scale, and a parameter that captures inter-firm contracting costs. While modeling the problem as a static game might seem unrealistic, it certainly has computational advantages in practice and could provide a good approximation to the problem if we estimate the model using data from the steady state.

He then takes the model to data on connection decisions at the well level and ownership structure from North Dakota. His estimates of the cost function suggest that inter-firm contracting costs are substantive and can prevent firms in fragmented markets from fully achieving economies of scale. In particular, he finds that a firm sharing the pipeline with another firm only achieves 59% of cost reductions from scale economies had all the well belonged to one firm. He then uses his model to evaluate the change in policy that took place in North Dakota in 2014 limiting the volume of gas flared. In particular, in counterfactual simulations he computes –as a benchmark– what connection would be like if there were no contracting costs between firms. He then calculates the flaring penalty that would bring about the same level of connection as in the previous counterfactual.

In terms of Andrés's research agenda, I anticipate that he will keep working on policy relevant issues in energy economics and environmental issues. In the short run, he has plans to keep working on the effects of the Medicare price transparency reform. In particular, he is interested in understanding the effects of price transparency on providers' behavior, like whether to show prices, and how to set them.

I have first met Andrés when I joined UT in 2017. Since then I have known him in many different capacities. As a student, he sat in my Empirical Industrial Organization course. He struck me as a very smart student, showing deep understanding of the economic concepts, and exceptionally able to deal with difficult empirical problems (like implementing structural estimators for production functions and auctions models). Given his excellent performance as a student, I decided to hire him as an RA on a project joint with Sukjin Han. In that project, we develop an empirical framework to identify and estimate the effects of treatments on outcomes of interest when the treatments are the result of strategic interaction (e.g., bargaining, oligopolistic entry, peer effects). We apply our method to data on airlines and air pollution in cities in the U.S. and Andrés was instrumental in the construction of our dataset that includes data from the DB1B airline tickets and several air quality indicators. He has always worked with great deliberation, thoughtfulness and care and in a proactive way. As a researcher, Andrés came up with the idea for this dissertation on his own and required little direction. He has shown to me that he is able to formulate an interesting problem, find a way to tackle it, and that he has the quantitate skills to execute it.

As I stated at the outset of this letter, Andrés is able to produce high-quality research. He has exceptionally strong quantitative skills. He is gentle and patient when people disagree or question him, but he is also quite capable of disagreeing and strongly defending his work. Given his skill set, I believe Andrés would be an asset to any department that values high-quality policy-relevant research. I would recommend Andrés to any Econ department outside of the top ten and to any Professional School or research institution with interests in energy and environmental problems..

Do not hesitate to contact me if you have further questions.

Best regards,

Jorge Balat

LYNDON B. JOHNSON SCHOOL OF PUBLIC AFFAIRS
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November 11, 2019

Dear Search Committee Members,

I am delighted to write this letter recommending Andrés Méndez Ruiz, a doctoral student in Economics at the University of Texas at Austin (UT), for a tenure-track assistant professor position in your department. I met Andrés in January 2018, when he enrolled in my doctoral environmental economics course. I was impressed with the research proposal he completed in my course, which developed into his job market paper, and I joined his dissertation committee shortly afterward. I am an environmental economist, and my own faculty appointment is at UT's policy school, the LBJ School of Public Affairs.

Andrés' dissertation work is at the intersection of I/O and energy/environmental economics. His job market paper focuses on oil producers in North Dakota's Bakken Shale, estimating the welfare cost of coordination problems in the development of infrastructure for bringing to market the natural gas produced during oil extraction. As you may know, there has been a lot of attention to the significant amount of natural gas flaring in the Bakken during oil production, primarily due to the lack of infrastructure to bring produced gas to market. In popular press coverage, gas flaring in the region is considered both wasteful and environmentally damaging. However, it is not clear that this behavior is economically wasteful, and this is the key question Andrés seeks to answer in his job market paper. His structural model assesses the costs and benefits of pipeline infrastructure investments from the firms' perspective, including economies of scale and positive spillovers, and he is able to demonstrate how private decision-making diverges from the social optimum. Though he has not yet gotten as far as considering environmental impacts in his welfare calculations, this will be a straightforward extension of his current work.

In 2014, North Dakota implemented flaring regulations that aim to reduce the share of flared gas over time. An NBER working paper by Lade and Rudik cleanly estimates the impact of those regulations on flaring using differences-in-differences, and compares the cost of the reductions achieved under the prescriptive approach used by the state to the cost of a hypothetical flaring tax. Andrés takes a completely different approach and asks a very different question with his paper. He models individual firms' decisions to invest in gas gathering pipelines and other infrastructure needed to bring the gas produced at each oil well to regional processing plants. One challenge he faces is determining the extent of the market for each processing plant's services – the set of firms that interact strategically in their decisions about what fraction of their wells will connect to the gas gathering network. His use of a K-means clustering algorithm for this purpose is creative, and it represents an innovation in the way economists model the decisions of oil and gas producers in this setting and others. Like much earlier work on unitization and other challenges of private ownership in common-pool resource extraction, his work is producing some generalizable results regarding the impact of fragmented resource ownership on welfare, and the capacity of regulation to act as a coordinating mechanism, in settings where coordination is likely to result in welfare gains.

I will leave it to Andrés' main advisors in the Economics Department to describe his other work in progress, and to compare him to his peers on the job market this year. My own view is that he would be a very good fit in any economics department below the top 25 (including departments in Europe and Latin America, given his fluency in four languages). The timeliness of his work on energy development and his interest in broadening his energy economics focus would also make him a good fit at many top policy schools, and in highly-ranked schools of the environment.

In addition to his promise as a scholar, Andrés is a pleasure to work with. He is very bright and well-trained, and his communication skills are strong. Given the focus of his research, I nominated him for a competitive fellowship in residence at the Property and Environment Research Center (a research organization) last summer. He received the fellowship and spent most of the summer in residence at PERC in Bozeman, Montana, where the visiting economists raved about his frequent helpful comments in seminars.

I recommend Andrés strongly for a position in your department. Please feel free to contact me by phone (512.471.2064) or by e-mail (sheila.olmstead@austin.utexas.edu), should you have any questions.

Sincerely,

Sheila M. Olmstead
Professor
LBJ School of Public Affairs
The University of Texas at Austin

THE UNIVERSITY OF TEXAS AT AUSTIN

20 November 2019

Chairman of the Junior Recruiting Committee

Dear Sir,

It is my pleasure to write this letter of recommendation on behalf of **Andrés Méndez Ruiz**, a graduate student from the University of Texas at Austin working at the intersection of IO and environmental economics that I have been supervising over the past few years. I have interacted with Andrés frequently since he took my IO graduate class three years ago. We have met regularly and he has presented his research in our graduate seminar three or four times per year. It took him a while to figure out an interesting research topic, as many other graduate students do, but persevered until one that I find very interesting.

Andrés is not only addressing an important policy issue related to gas emissions and global warming, but also, more importantly, how the effectiveness of regulations might be hampered by contracting frictions among firms and the oil industry market structure. This is a very creative approach aiming to separate the effect of economies of scale from firms' need to coordinate joint investment in infrastructure to reduce gas flaring effectively. In my opinion Andrés deserves attention by departments interested in building well-founded applied micro groups, including Public Policy or Natural Resources schools interested in hiring environmental economists well-trained both in theoretical and current empirical methods in IO.

Andrés' job market paper addresses the difficulties that oil companies encounter to reduce flaring of natural gas when extracting oil. Oil and natural gas are produced jointly but the latter is particularly costly to capture and transport, and thus it is flared, i.e., burned off directly into the atmosphere. There is no doubt that the environmental damage that this creates motivates regulators to force the oil industry to reduce this flaring. However, implementing this regulation encounters difficulties intrinsic to the nature of the industry and its market structure: firms own oil wells scattered over fields and transporting gas requires the construction of gathering pipelines. However, no single firm has an incentive to build these pipelines by itself because as they are built other firms will connect to the network of pipelines at a lower cost. This is a classic example of the tragedy of anticommons where coordinating costs and contracting frictions among individual firms impedes them reducing the cost of regulatory compliance. In the absence of all these frictions, firms will build the gathering pipelines faster and at a lower cost. Andrés' approach is to use the existing connections between oil wells and processing plants in North Dakota to recover the magnitude of these friction costs by measuring the "external" economies of scale, i.e., the reduction in production costs of having other firms connected to the network. The counterfactual analysis produces an estimate of these friction costs by assuming a different ownership structure where all wells belong to a single firm.

Using data from North Dakota, Andrés estimates a model of pipeline construction and flaring that takes into account these economies of scale and potential coordination/contracting problems in a pipeline connection game of complete information. With his estimated structural model, he is able to assess the extent to which market fragmentation impacts pipeline construction and flaring, and how various policies might reduce this

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flaring. Andrés builds a structural model to address this anticommons problem widely ignored in the empirical literature. The modelling abstracts from dynamics which firms builds a section of pipelines first but offers a framework to obtain reasonable estimates, using sophisticated indirect inference methods, given the current data limitations that exclude the exact location of oil wells. I see his work as a remarkable first step that allows him to simulate credibly pipeline construction under alternative industry structures. This important contribution identifies the magnitude of contracting frictions hampering the desirable reduction of gas flaring in oil extraction and highlights how the effectiveness of flaring regulations might vary with industry ownership structure.

I am writing letters for two students on the junior market this year. Yeon-Joon Lee is a finance candidate who makes use of common IO estimation methods. I feel he is better suited for finance departments. Andrés is an IO economist better suited for an Economics department that appreciates good empirical work with a sound theoretical foundation. In writing his job market paper, Andrés has also acquired a great deal of knowledge of the oil and gas industry and their regulation, which in my opinion makes also him an interesting candidate for a Public Policy School interested in building an environmental group.

Andres is inquisitive, very well read, and technically capable. He is a very motivated and committed researcher that has even convinced me to collaborate with him and another graduate student in a project dealing with unitization of oil fields once he graduates. He will also prove to be an excellent colleague and effective and dedicated teacher, as I can attest because he was also my TA for my undergraduate IO class.

Do not hesitate to contact me should you need any additional information about Andrés or his work. Yours,

Eugenio J. Miravete
Rex G. Baker Jr., Professor of Political Economy
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Coase on Fire: Regulation and the Adoption of Natural Gas Flaring Abatement Technology in North Dakota

Andrés Méndez-Ruiz*

Draft: November 27, 2019

Abstract

Unconventional fossil fuel extraction technology and favorable market conditions ignited an oil production boom in North Dakota. At its onset, around 2008, the state lacked enough pipeline infrastructure to capture all the associated natural gas extracted jointly with oil, resulting in large volumes of flared natural gas. Against this backdrop, I investigate the role of contracting costs in hindering firm cooperation in constructing pipelines, thus preventing firms from fully harnessing available mutual economies of scale. To do so, I model firms' well-connection decisions as a static complete information game in which producers decide what fraction of their wells to connect, while considering the effect of externalities from other producers' actions on their own connection costs. I measure the extent of inter-firm contracting costs with respect to a benchmark case in which all wells are owned by a single firm, and as such, inter-firm contracting costs are assumed to be zero. I also use my model to study what the investment outcome would be if contracting was costless in that sense. Finally, I compute a counterfactual to determine what flaring penalty would result in market-level outcomes mimicking those of a single firm.

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*Department of Economics, The University of Texas at Austin. Email: andres.mendez@utexas.edu. I am grateful to Daniel Ackerberg, Eugenio Miravete, and Jorge Balat for their advice and encouragement. Thanks to Sheila Olmstead for her support and observations. I would also like to thank Robert Town for his insightful comments. I am grateful for the financial support I got from the Property and Environment Research Center through the PERC Graduate Fellowship. I thank my mentors and fellows at PERC during the summer of 2019 in Bozeman, Montana for their valuable comments.

1 Introduction

Opportunities exist for firms in many industries to share the costs of building and operating infrastructure for industrial production, the supply of goods and services, or waste management.[1] For this type of inter-firm cooperation, firms must contract with each other. Inter-firm cooperation and its outcome are therefore largely determined by the magnitude of inter-firm contracting costs. To the extent that cooperation is successful, it enables firms to harness available economies of scale by increasing the size or reducing the cost of a given infrastructure project. The collective provision of quasi-public goods of this nature also creates cost interdependencies among firms, which result in strategic behavior when selecting investment or technology adoption levels. This type of collective provision of quasi-public goods by firms has not been studied empirically.[2] To fill this gap in the empirical literature, I use North Dakota's natural gas-gathering infrastructure deployment as a case study to investigate this fundamental source of investment externalities.

Oil and gas are jointly produced. A play is an area containing accumulations of hydrocarbons that exhibit similar geological characteristics. In plays where most of the value of drilling wells comes from oil, capturing the associated natural gas "is an economic afterthought for producers" (Davies [2013]). In addition, there is only one option for transporting natural gas effectively. While oil can be transported using pipelines, trucks, or trains, gas transportation requires pipelines, which are high fixed-cost investments. If production begins before a well has been connected to a natural gas pipeline, the associated natural gas must be flared. Flaring is the controlled combustion of unprocessed natural gas.

In North Dakota, the first unconventional well was drilled in 2007. The oil boom that followed placed North Dakota second among U.S. states in terms of oil production. However, the state's insufficient natural gas pipeline infrastructure resulted in the flaring of large volumes of associated natural gas. In July 2014, because of concerns about waste and the environment, the North Dakota Industrial Commission (NDIC) released new flaring regulations (Commission Order 24665). The objectives of these regulations were to reduce the volume of gas flared, the number of wells flaring, and the duration of flaring from wells (NDIC [2014]). The new regulations established flaring targets, required gas-capture plans to obtain drilling permits, and established penalties for noncompliance.[3] To comply with

[1] Examples include airports, ports, and irrigation systems. See Young [1985].

[2] Building natural gas-gathering infrastructure can be viewed as a problem of reaching an agreement for the sharing of benefits and costs of a quasi-public good with exclusion, or of a club good (Buchanan [1965]; Sandler and Tschirhart [1980]).

[3] In July 2014, the NDIC (or Commission) released a new set of regulations requiring North Dakota's oil and gas producers to reduce natural gas flaring to 26 percent of total gas production by October 2014,

the required gas-capturing targets, producers need to connect a larger fraction of their wells to the gathering pipeline network (Lade and Rudik [2019]). The question is whether and how much these flaring regulations would lower firms' contracting costs.

In this paper, I analyze the relationship between market structure and firms' technology adoption decisions in the presence of positive investment externalities. The underlying question is whether the costs (both physical and transactional) of building natural gas-gathering pipelines are greater when more firms are present. Ownership fragmentation can result in contracting costs, which in turn can prevent firms from achieving an efficient infrastructure investment level. By connecting more of their own wells, firms exploit economies of scale without needing additional contracts to do so, whereas to achieve economies of scale with other producers, firms need to contract with each other, and this could be costly. Organizational structure then becomes relevant for efficiency.

My goal is to investigate the potential welfare gains from policies that facilitate the collective provision of quasi-public goods by firms. Because the efficient scale for gathering natural gas is small with respect to the size of the U.S. natural gas market, I do not consider market power effects in my analysis.[4] My analysis ultimately contributes to answering the following question: From the perspective of the oil and gas industry, is flaring, a physical waste, also an economic waste?[5] If present, contracting costs may result in market failure where gathering infrastructure is under-provided and excessive flaring occurs.

According to the Global Gas Flaring Reduction Partnership (GGFR), around four percent of the global natural gas output (145 billion cubic meters) is flared annually.[6] In some producing regions, such as North Dakota, the percent of gas flared is even larger. The amount of gas flared annually could provide about 750 billion kWh of electricity, which is more than Africa's annual electricity consumption. According to the Environmental Protection Agency (EPA), the climate impact of flaring 145 billion cubic meters of natural gas is equivalent to the

23 percent by January 2015, 20 percent by April 2016, 12 percent by November 2018, and nine percent by November 2020. Also, according to these new rules, capture plans must include signed confirmation that a gas-gathering company has been contacted and will meet the new demand as soon as possible.

[4] Williamson [1968] argues that the trade-off between efficiency gains and higher prices should be considered when analyzing the welfare effects of mergers. Note, however, that if firms cannot increase prices after a merger, monopoly becomes the benchmark for efficiency. Avalos et al. [2016] fail to reject the hypothesis that there is a single well-integrated natural gas market in the United States.

[5] According to Fitzgerald [2018] the key legal question surrounding flaring is whether the cost of capturing, processing, and marketing the associated natural gas exceeds its value.

[6] The global totals of natural gas flared for the years 2013, 2014, and 2015 were 140.8, 145.3, and 147.3 billion cubic meters, respectively. The GGFR is a publicprivate initiative led by the World Bank in Washington, D.C. It comprises international and national oil companies, national and regional governments, and international institutions. The goal of the GGFR is to increase the use of natural gas associated with oil production.

emissions from 60 million passenger vehicles driven for one year or 80 coal fired power plants in one year.[7] Furthermore, emissions from flaring constitute around two percent of the total worldwide emissions from energy sources. Thus, it is not a surprise that flaring has become a controversial environmental issue, and efforts to reduce it have emerged at the regional, national, and international levels, such as the World Bank's "Zero Routine Flaring by 2030" initiative.

The United States is among the top five flaring countries (see Figure A.1). Moreover, the volume of natural gas flared in the United States almost doubled from 2010 to 2015. The two states that flare the most natural gas are Texas and North Dakota (see Figure A.2). In the United States, the increase in flaring can be attributed mainly to unconventional oil extraction (fracking). Fracking has enabled oil producers to expand their operations to previously unproductive formations. Many such formations are in regions that lack sufficient natural gas-capturing infrastructure. This has created a challenge for local governments regarding how to deal with flaring. Understanding the economics of flaring is crucial for designing sound flaring reduction policies, especially because there are several prospective shale plays that will likely start being developed in the near future (see Figure A.3).

When strong winds prevail, flaring is likely to result in the incomplete combustion of natural gas. Incomplete combustion generates more harmful pollutants than fully burning the gas (Bott [2007]; Ismail and Umukoro [2016]).[8] Pollutants from flaring include carbon dioxide (CO_2), carbon monoxide (CO), volatile organic compounds (VOCs), nitrogen oxide (NOx), sulfur dioxide (SO_2), toxic heavy metals, and black carbon soot (Ite and Ibok [2013]). Therefore, it is not surprising that flaring has been associated with negative health outcomes (Kindzierski [1999]; Gobo et al. [2009]; Ajugwo [2013]). In North Dakota, flaring has resulted in the local worsening of respiratory health outcomes (Blundell and Kokoza [2017]). Natural gas capturing could greatly decrease these health and environmental externalities. In power plants, natural gas combustion occurs in a more controlled environment, and existing abatement technologies can be used to reduce pollutant emissions.

My strategy for measuring inter-firm contracting costs in this industry proceeds in four steps. First, I develop a structural model of firm natural gas gathering infrastructure investment. In this model, producers play a static, complete information adoption game in which they decide what fraction of their wells to connect given ownership structure, market size, and the strategies of the other firms in the same market. Second, I divide the oil and gas wells of

[7] The equivalences were computed using the EPA's Greenhouse Gas Equivalences Calculator, available at: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator

[8] Combustion efficiency is measured as the ratio of carbon dioxide produced by the flare to the mass of carbon in the fuel (Ismail and Umukoro [2016]).

North Dakota into markets for natural gas gathering. A market is a group of wells within a geographic region that would likely share the same gathering system and hence potentially benefit from scale economies in constructing that gathering system. Third, using data on firms' gathering pipeline adoption rates at the market level, I recover parameters that are consistent with the underlying model. Fourth, I use my structural model to compute the changes in policy-relevant quantities, such as the quantity of wells connected and the volume of flared natural gas that would result if a single firm owned all the wells in a market. I also calculate the flaring penalty that would bring about market-level adoption decisions mimicking behavior by a single firm.

The structural model I take to the data has two key parameters. The first governs economies of scale (i.e., the curvature of the cost function). Identification of this parameter follows from variation in the number of wells across markets. The second key parameter of the model measures inter-firm contracting costs. This parameter is identified from variation in market structure. To the extent that firms neglect natural gas revenues when determining where to drill wells, it seems sensible to treat market structure as exogenous to firms' decisions whether or not to connect their wells to the gas-gathering system. Thus, the variation in firms' well connection rates across observationally equivalent markets, except for their well-ownership concentration level, contains information about the costs of contracting. The technology adoption game that firms play can have multiple equilibria. Under-adoption of natural gas-capture infrastructure can also result from the selection of a Pareto dominated equilibrium (Dybvig and Spatt [1983]; Farrell and Saloner [1985]). The supermodular nature of the game, however, makes it possible to select the Pareto-best equilibrium using an iterative procedure, as in Gowrisankaran and Stavins [2004] and Ackerberg and Gowrisankaran [2006].

I estimate the model's parameters using the method of simulated moments (MSM), which was introduced by McFadden [1989] and Pakes and Pollard [1989]. The estimation algorithm, which searches over the parameter space, includes an inner-loop that simulates the Pareto-best equilibrium of the game for each of the firm-market-level unobservable simulation draws. I construct simulated moment conditions using the observed connection rates and the expected value of the simulated equilibrium connection rates. According to my estimation results, contracting costs prevent firms in fragmented markets from fully achieving economies of scale. In particular, wells owned by another firm in the same market achieve only 59 percent of the marginal cost reductions that a well owned by the firm itself achieves. I interpret this 41 percent difference between the intensities of cost synergies from wells owned by a firm and those owned by others as a measure of contracting costs.

After recovering estimates of the underlying model parameters, I estimate counterfactual adoption rates consistent with costless inter-firm contracting. To do this, I simulate the equilibrium of the game that would result if firms faced the marginal costs that a single firm that owned every well in the market would face. I find that 131 additional wells would have been connected to the gas-gathering network if firms in a fragmented market could costlessly contract with each other. According to my model, this is also the outcome that would prevail if a single firm owned all the wells in a market. In addition, I use my model to compute the penalty that approximates the investment outcome that would result if a single firm owned every well in each market. I find that a penalty of $2,555 USD per unconnected well would achieve this outcome.

The reminder of the paper proceeds as follows. Section 2 reviews the related literature. I then provide some basic institutional background on the oil and gas industry in Section 3. In Section 4, I present a stylized equilibrium model of technology adoption and cost-sharing. Section 5 explains the data, describes the relationship between well connections and market structure in the data, and presents evidence suggesting that inter-firm contracting results in pipeline under-adoption. In Section 6, I discuss the estimation procedure, identification of the main parameters of the model, and present my estimation results. In Section 7, I use the estimated model to measure contracting costs and counterfactual adoption rates. I conclude in Section 8. In the Appendices, I describe additional descriptive statistics and other results.

2 Related Literature

In this section, I discuss the contribution and position of this paper with respect to the existing literature. From a broad perspective, this article contributes to the literature documenting contracting frictions resulting in firm and industry under-performance. It adds to the understanding of the relationship between industry horizontal structure and cost efficiency. In a narrower sense, this paper contributes to the literature investigating the economics of the fracking boom, and more specifically of natural gas flaring

This paper is related to four strands of literature. First, it is related to the literature on inter-firm contracting. Several papers explore the relationship between organizational form and firm performance. Mullainathan and Scharfstein [2001] find differences in production capacity investments between vertically integrated and non-integrated chemical manufacturers. Ciliberto [2006] finds that hospitals that formed joint ventures with physicians invest more in healthcare service expansion. Forbes and Lederman [2010] find that large U.S.

network carriers that use owned regional airlines perform systematically better than those contracting with independent regional airlines. This paper extends this first strand of related literature by focusing on the effect of horizontal, rather than vertical, integration on investment. Moreover, because I estimate a structural model, I can compute welfare losses from fragmented ownership.

To the best of my knowledge, few papers in the empirical industrial organization literature have estimated the costs of contracting and their welfare effects structurally. One of these is Bajari et al.'s [2014] paper, which investigates the effect of *adaptation costs* on bidding behavior for highway paving procurement contracts.[9] This paper adds to this effort by building and estimating a structural model that provides evidence on how industry structure affects contracting costs involving a large number of firms.

Furthermore, an interesting feature of the gathering pipeline industry is its network structure, which can increase the costs of contracting. Forbes and Lederman [2009] find evidence that major U.S. airlines are more likely to use owned regional airlines on routes that are more integrated with their own network. The reason for this is that the optimal response to a disruption depends on the conditions elsewhere in the entire network, giving rise to a large set of contingencies that would be very costly to cover in a contract. Industries with a network structure pose additional contracting challenges because reaching a beneficial agreement in these industries involves multiple parties (Milgrom [2017]).

Second, this paper contributes to the literature that analyzes the role of externalities in firms' technology adoption decisions. There are only a few empirical studies on this subject because it is difficult to find adequate data. Gowrisankaran and Stavins [2004] measure the extent of network externalities for the automated clearinghouse (ACH) electronic payments system in the banking industry. Their results suggest that the ACH is underused because of market failure caused by network externalities. Ackerberg and Gowrisankaran [2006] extend the analysis of network externalities for the ACH by estimating an equilibrium model of technology adoption in this industry. In contrast, I investigate the role of production externalities on firms' investments. In particular, I analyze externalities resulting from sharing the costs of infrastructure provision when the cost structure is submodular. This is the first study examining this type of strategic cooperation in the empirical industrial organization literature.

Third, this paper is also related to the economic literature on the oil and gas industry. A couple of papers have analyzed contractual arrangements in the natural gas industry. Mas-

[9] Adaptation costs include disruption of the normal flow of work and renegotiation costs resulting from haggling, dispute resolution, and opportunistic behavior (Bajari et al. [2014]).

ten and Crocker [1985], Crocker and Masten [1988, 1991], and Hubbard and Weiner [1991] present evidence indicating that contract design is geared towards enabling adaptation and mitigating ex-post opportunistic behavior. In this paper, I shift the focus from contract design to measuring potential inefficiencies resulting from misalignments between organizational form and the contracting environment in the natural gas industry.

The relevance of ownership structure and contractual arrangements for efficiency has been documented in the oil industry. Libecap and Wiggins [1984] study inter-firm contracting in response to externalities from common pool resource extraction. They find that contracting success is largely determined by within-field ownership concentration. They also find that the more efficient contracting solutions are often not adopted because of high bargaining costs.[10] Balthrop and Schnier [2016] compare regulations to mitigate common pool externalities in Oklahoma and Texas. They find that Oklahoma's stricter compulsory unitization policy results in higher cumulative oil production. Leonard and Parker [2019] investigate which ownership regime (private vs. public) generates greater resource use in the context of the shale oil industry.

Finally, this article adds to the literature on the supply-side effects of environmental regulations. Lade and Rudik [2019] study the effects and efficiency of the flaring regulations introduced by the NDIC in 2014. They find that the introduction of the new rules reduced flaring rates by four to 17 percent over the first year of a well's productive life. Moreover, their findings show that firms comply by connecting their wells more quickly to pipeline infrastructure and taking longer to complete their wells. My paper is different than theirs, as I emphasize the strategic aspect of gathering infrastructure investments, whereas they focus on firm-specific abatement costs. Additionally, my goal is to investigate whether or not the NDIC flaring regulations lowered inter-firm contracting costs, whereas they focus on the inefficient allocation of compliance costs across firms.

3 Industry Background

In North Dakota, during the period of my analysis, the main bottleneck resulting in natural gas flaring was a shortage of gathering pipelines. Gathering pipelines are small-diameter pipelines -typically ranging from eight to 30 inches in diameter- that collect natural gas from wells and bring it to the processing plants. Insufficient gathering infrastructure at the onset of the fossil fuel extraction boom and the fact that crude oil and natural gas are jointly

[10]The authors consider three possible contractual solutions: consolidation, unitization, and prorationing.

produced resulted in large amounts of natural gas being flared in North Dakota (Davies [2013]). Flaring is the consequence of decisions taken by upstream hydrocarbon producers and the interactions between those producers and midstream pipeline companies. I will therefore describe oil and gas production and the midstream in more detail below.

3.1 Oil and Gas Production and Transportation

Oil and gas are jointly produced. After a well has been drilled and completed, the extraction of reservoir fluids begins. Reservoir fluids are a mixture of oil, gas, and water in proportions that depend on the geological characteristics of the reservoir. The gas-oil ratio (GOR) of a well determines whether it is classified as an oil or natural gas well. In oil plays in which most of the wells' profits come from crude oil, capturing the associated natural gas "is an economic afterthought for producers" (Davies [2013]). In the Bakken, for example, oil revenues represented around 87 percent of the value of a typical well in November 2012 (Davies [2013]). In plays like this, it is likely that the decision of where to drill wells is mostly determined by factors that enable firms to maximize profits from crude oil. To the extent that this is the case, the location of wells and ownership structure are exogenous to the decision of whether or not to connect a well to the gathering network. Additionally, producers must drill at least one well before the primary term of an oil and gas lease expires, or they will lose the lease. Therefore, producers often make drilling decisions to ensure that most of their leased acreage is "held by production" (Henderson [2012]; Herrnstadt et al. [2019]).

Once on the surface, the well stream passes through a series of separation and treatment devices that segregate the reservoir fluids into oil, gas, and water. Oil is moved to a refinery through a pipeline, truck, or train. Whenever available, gathering pipelines receive the natural gas from the well sites. Depending on its quality, natural gas is sent to a processing plant or is directly injected into a gas transmission line (Miesner and Leffler [2006]; Economides et al. [2012]; PETEX [2011]).[11] Usually, if a well has no connection to a gathering pipeline, natural gas must be vented or flared because, unlike crude oil, generally speaking there are no other feasible alternatives to transport it to the market.[12] Flaring is the controlled combustion of unprocessed natural gas, and it is done for environmental and safety

[11]If the raw gas is "dry," that is, has low fractions of natural gas liquids (NGLs), it can be injected directly into the transmission lines; otherwise, it needs to be processed first. The reason for removing the NGLs is twofold. First, if these are not removed they can condense while inside the transmission pipelines, thus clogging them. The second reason is that NGLs have a higher market value than methane. Therefore, there is an economic incentive for selling them separately.

[12]Releasing gas into the atmosphere is called venting.

reasons.[13]

Gathering pipelines connect a large number of wells into pipeline webs that collect natural gas. They start at well sites, and their function is to collect the raw gas from producing areas and transport it to processing plants or, in some cases, to the transmission lines directly. Raw gas is a mixture that contains mostly methane, some water vapor, and NGLs, such as ethane, propane, butane and natural gasoline. Once it has been processed, natural gas enters the transmission pipeline system. Transmission pipelines transport natural gas from processing plants to the final consumers (Miesner and Leffler [2006]; Webber [2014]).

While there are some fully integrated companies that control both production and gathering, most producers rely on stand-alone midstream operators to collect their natural gas output. Stand-alone midstream companies invest in coordination with one or more *anchor shippers*, which make long-term commitments. Pipeline construction follows the confirmation of sufficient producer commitments. This leads to strategic behavior and cost-interdependencies between producers because the costs of building a gathering system, and ultimately its provision, depend on the adoption decisions of all the firms operating neighboring wells within a region of the play. Gathering companies allow producers to share the costs of providing gathering infrastructure.

3.2 Gas Gathering Agreements and Contracting Costs

Production and midstream companies negotiate agreements for gas gathering. The existence of independent gathering companies enables producers to share the costs of transporting natural gas from their wells to the processing plants. Vertically integrated firms, operating both wells and pipelines, can also sign contracts with other producers operating nearby wells to share the costs of building gathering pipelines (Mulherin [1986]; Kennedy [2017]). Contracts between producers and gathering companies are long-term, lasting typically around 10 years. Once a contract expires, producers and gathering companies renegotiate the terms of their agreements. Natural gas-gathering agreements include several services: treatment of the raw gas to remove hydrogen sulfide and carbon dioxide, dehydrating the gas, transporting the gas from the wellhead to the processing plant, and compressing the gas (Krafka and Strawn

[13] Natural gas consists mostly of methane, which has a higher radiative force than the carbon dioxide, which results from methane combustion. Because methane is twenty-three times more powerful than carbon dioxide in trapping heat in the atmosphere over a hundred-year period, it is less harmful for the environment to flare methane than to just vent it. Moreover, natural gas has no natural odor. Therefore, venting poses serious risks. For example, natural gas could remain undetected, accumulate, and eventually explode (Ehrman [2014]; Webber [2014]).

Figure 1: Natural Gas Gathering Lines

Source: https://www.entecheng.com/en-us/projects-gallery/natural-gas-client-natural-gas-gathering-system_8

[2017]).

One of the main components in gathering agreements are *dedications*. Dedications are guaranteed fees tied to a set of wells, acreage, or output of natural gas throughout the life of a contract. These guaranteed fees provide midstream companies a stable source of revenues. Generally, the language in the contracts is such that well or acreage ownership transfers include the terms of the agreement with the gathering company. In other words, dedications are tied to the property and not the owner (Miesner and Leffler [2006]; Kennedy [2017]).

The more fragmented ownership is in a market, the more contracts are required for a project to be large enough to be feasible. In the context of natural gas gathering, fragmented ownership of wells can increase contracting costs. There are at least four types of costs that could increase depending on the number of producers. First, enforcing a larger number of contracts results in additional legal fees. Second, because most of the costs of pipeline construction are sunk, there exists the risk of a holdup by the producers who want ex-post better terms, resulting in yet more negotiation costs. Third, costs can result from disagreements among owners about how the gathering system is operated. For example, in a scenario where higher-pressure wells can disrupt the flow of natural gas from lower-pressure wells, fragmented ownership could lead to costly disagreements about which wells to connect. Finally, costs to resolve disputes between parties become greater as the number of owners increases.

3.3 Anecdotal Evidence

There exists anecdotal evidence highlighting the importance of economies of scale and contracting costs in the provision of natural gas-gathering infrastructure. For example, in a report prepared by the Energy Executive of the Governor of Pennsylvania, several recommendations were made to improve efficient placement of natural gas pipelines. One of the recommendations made in the report highlights the importance of encouraging firms to share the costs of providing gathering infrastructure:

> "Country planning offices should be encouraged to work with drilling operators and gathering line companies so that operators and companies understand current and future development plans and can seek to maximize opportunities to share rights-of-way and pipeline capacity." (Henderson [2012])

Additionally, a report by Carbon Limits AS stresses the importance of economies of scale and inter-firm coordination for reducing natural gas flaring:

> "[...] producers have sought to achieve economies-of-scale by buying, selling, and trading assets to increase the size of their continuous lease acreage. This tendency for unitization of activities within an area by a single operator could help reduce flaring of associated gas, as coordination among different, neighboring well operators to develop gas gathering infrastructure increases." (Pederstad [2015])

The cost of enforcing gathering agreements have been documented in the news. Specifically, an article by the Wall Street Journal (WSJ) describes the conflict between shale producer Exco Resources Inc. and pipeline operator Williams Cos. A dispute between these two parties originated because the producer was seeking permission from the Texas Railroad Commission to flare the natural gas from a set of wells in South Texas that were already connected to the gathering network operated by Williams Cos. This is an example of a holdup, where the pipeline company cannot guarantee that it will recover its sunk investment ex-post. This WSJ article also describes producers' reluctance to sign long-term contracts for natural gas gathering (Elliott [2019]).

3.4 North Dakota's Boom

Historically, North Dakota was not a large oil-producing state. This changed with the drilling of the first unconventional well in the Bakken formation in 2007.High oil prices, which crossed the $100 per barrel threshold in multiple occasions after 2008, created a favorable environment for the widespread adoption of directional drilling and hydraulic fracturing. Fracking enabled producers to unlock crude oil and natural gas trapped in the otherwise almost impermeable shale rock underneath North Dakota.[14]

The success of unconventional extraction was such that, in March, 2012, North Dakota surpassed Alaska to become the second most prolific oil-producing state in the United States, after Texas (Covert [2015]). According to data from the EIA, North Dakota's monthly oil production went up from 3.5 million barrels of oil in January 2007 to 29.1 million barrels in December 2016 at an average monthly production growth rate of 1.94 percent (see Figure A.4).[15] This sudden increase in oil and gas took the state by surprise. The state lacked sufficient pipeline infrastructure to transport oil and gas to its potential buyers. In contrast to crude oil, natural gas cannot be efficiently transported by train or truck because of its gaseous, rather than liquid, state at usual temperatures (Ehrman [2014]).

Furthermore, oil was more valuable per million British Thermal Units (MBTUs) during the 2010-2016 period. The 2010-2016 average spot price of natural gas was $4.38 per MBTU, while oil was sold in the spot market at an average price of $14.02 per MBTU during the same period (see Figure A.4).[16] This disparity between the prices of oil and gas provided incentives for upstream producers to further extract oil despite having to treat natural gas effectively as a waste (EPRINC [2012]). In Figure 2, I present a graph of the state-level evolution of the amount and the percentage of flared natural gas. As observed, during 2013-2014, monthly volumes of flared gas surpassed 11,000 MMCF.

[14]Unconventional wells are those drilled into shale rock plays, which need to be fractured for commercial production of oil and gas to be possible (PETEX [2011]). Hydraulic fracturing is the high-pressure pumping of water into a reservoir to crack open the shale rock. A proppant, such as sand, is then pumped into the cracks to keep them open (Cheremisinoff et al. [2015]; Webber [2014]). Fracking needs to be combined with horizontal drilling, which increases the area of contact between the well and the reservoir to improve productivity (Mokhatab and Poe [2015]). Above normal prices were necessary to trigger North Dakota's production boom because unconventional oil and gas extraction is more costly than conventional extraction.

[15]Figure A.4 also shows the state's monthly gas production in million cubic feet (MMCF), which tracks the evolution of oil production because the two fuels are jointly produced. Note that the output decline observed towards the end of the period in Figure A.4 coincides with sharply declining oil prices.

[16]BTU is an energy unit. The amount of energy in one BTU is approximately equivalent to the energy of a kitchen match. The energy content of one thousand cubic feet (MCF) of natural gas is approximately equivalent to 1.037 million BTUs, and the energy content of a barrel of crude oil is approximately equivalent to 5.8 million BTUs (Webber [2014]).

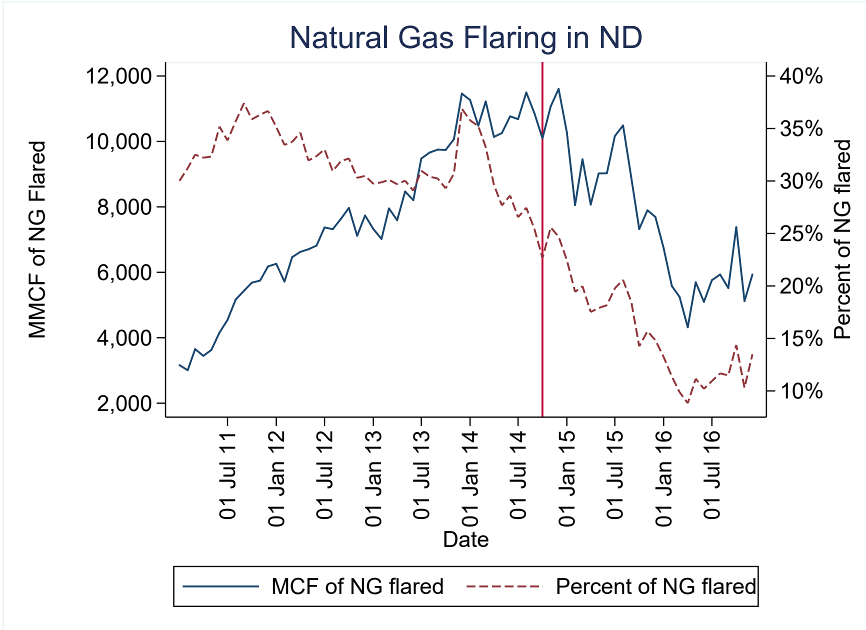

Figure 2: Flaring in North Dakota

Note: At its peak, around 37.5 percent of North Dakota's gas output was flared.

3.5 NDIC Flaring Rules

In July 1, 2014, the NDIC released Order 24665, containing a new set of regulations requiring upstream producers to take incremental steps through 2020 to reduce natural gas flaring. As stated by the NDIC [2014], the goals of these regulations are "to reduce the flared volume of gas, reduce the number of wells flaring, and reduce the duration of flaring from wells." To achieve this, the new policy introduced limits on the amount of gas that firms could flare without consequences starting that same year, on October 1. Also, new requirements were added for obtaining drilling permits. Beginning June 1, 2014, it became compulsory for producers to present a gas-capture plan before receiving authorization to drill new wells. These capture plans must include a signed confirmation that gas gathering companies are going to be able to meet the new demand as soon as possible (Dawson [2014]; Ehrman [2014]; NDIC [2014]).

The new policy establishes the following gas-capture goals: 74 percent from October 1, 2014 through December 31, 2014; 77 percent from January 1, 2015 through March 31, 2016; 80 percent from April 1, 2016 through October 31, 2018; 88 percent November 1, 2018 through October 31, 2020; and 91 percent beginning November 1, 2020.[17] These goals apply at the

[17]The original incremental gas-capture goals included in Order 24665 required firms to capture 74 percent of the gas by October 1, 2014, 77 percent by January 1, 2015, 85 percent by January 2016, and 90 percent by

firm level (NDIC [2014]; NDIC [2014]). Producers that are unable to attain the NDIC's capture goals are subject to production curtailments and fines up to $12,500 per offense, per day. The Commission identifies wells owned by noncomplying firms that are flaring a greater percentage of gas than allowed by the flaring rules. These wells are then restricted to producing 200 barrels of oil per day if at least 60 percent of their monthly gas output is captured; otherwise, their oil production is capped at 100 barrels per day.

The new rules set in place by the NDIC appear to have had an effect in terms of curbing natural gas flaring. After the regulations came into effect in the last quarter of 2014, the monthly level of natural gas flared and the percent flared from total gas production started to decrease. In Figure 2, it can be observed that, at its peak, around 35 percent of North Dakota's natural gas production was flared. After the flaring rules were passed in October 2014, the amount of natural gas flared in absolute value, and as a percentage of total production, started to decrease.

4 A Technology Adoption Cost-Sharing Game

In this section, I present a stylized model of the producers' decisions to connect their wells to the natural gas-gathering network. I model these decisions as the outcome of a static complete information game among upstream firms (producers) that own wells in the same market. In my model, a shale play is divided into markets for natural gas gathering. A market is a geographic region in which firms can share the investment costs of building pipelines to transport natural gas from their wells to a processing plant. Therefore, a market limits the group of firms that interact strategically when choosing what fraction of their wells to connect to the gas-gathering network. Choices across markets are independent.

The key component of my model is a flexible parametric cost function that allows (but does not impose) economies of scale, inter-firm cost synergies, and contracting costs.[18] If the value of the parameter governing the curvature of the cost function falls in a region in which there are economies of scale, a firm can achieve them by connecting more wells. Inter-firm cooperation enables firms to harness more of the available scale economies by increasing the size or reducing the costs of a given infrastructure project. This type of cooperation results in lower marginal connection costs and gives rise to cost interdependencies among firms. In turn, these interdependencies lead to strategic behavior, as the connection costs that each

October 1, 2020. Nevertheless, some minor changes were introduced to the original targets in the Guidance Policy for Order 24665 published by the Commission.

[18] In my model transaction costs govern the "intensity" of the positive cost externalities.

producer faces become dependent on the connection choices made by the other producers in the same market.

I make a series of assumptions with the goal of keeping my model simple so that the structure of the game does not obscure my analysis. For example, I do not include within-market geography in my model. Neither the exact location of a well nor its distance to the nearest processing plant play a role in my model. I make this simplifying assumption because, if I allow firms to choose which wells to connect based on well-level characteristics, the order of the well connections would become a relevant component of firms' strategies. If the order of connection matters, the structure of my model would have to be that of a sequential game with a rich combinatorial structure, and solving games with a rich combinatorial structure is not trivial. More importantly, a static model of strategic behavior is adequate for understanding the relationship between ownership structure, economies of scale, and technology adoption in my application, as the relationship between these variables results from more long-run interactions among firms.

As an additional modeling device, I assume that each firm owns a continuum of symmetric wells. Symmetry means that the type of each well in the continuum is drawn from the same distribution. Symmetry implies that the masses of wells owned by each firm are equidistant from the processing plant, and that wells are equidistant from each other. Assuming symmetry allows me to use the Cartesian product of the fraction of wells connected by each firm as the relevant action-space over which the strategic interaction takes place. Furthermore, the assumption of a continuum of wells makes the modeling of the relationship between market fragmentation and market-level outcomes tractable.

An important feature of the model is that, in the spirit of transaction cost economics, the unit of analysis is the transaction (i.e., a well connection). To the extent that there are no transaction costs or coordination problems, a market with multiple firms is indistinguishable from a single firm, holding the mass of wells and other characteristics constant. Only to the extent that one form of organizing transactions is more efficient than the other will the outcomes between observationally equivalent markets with a single firm and those with several firms diverge.

4.1 Technology Adoption in Markets with a Single Firm

I will start by explaining how a firm chooses what fraction of its mass of wells to connect when it is the only producer active in a market for natural gas gathering. This will simplify the exposition of the mechanics of the cost function before generalizing the model to a setting where multiple firms operate in each market, adding externalities and strategic interaction. In this simplified setting, a single firm in market m owns a continuum of wells, indexed by i, of total mass I_m. Wells are homogeneous up to an idiosyncratic well level unobservable with cumulative distribution function $G_\epsilon(\epsilon)$.

The problem of the firm is to decide what fraction, f_{1m}, of its wells to connect to the natural gas-gathering network. The profits of the firm, in utils, from connecting a fraction f_{1m} of the wells it owns to the gathering network are given by:

$$\Pi_{1m}(f_{1m}) = \underbrace{\lambda r_m f_{1m} I_m + [\int_{\underline{\epsilon}=G_\epsilon^{-1}(1-f_{1m})}^{\infty} \epsilon_{im} g_\epsilon(\epsilon_{im}) d\epsilon_{im}] I_m}_{\text{Revenues}} - \underbrace{\widetilde{TC}_m(f_{1m}, I_m; \theta^c)}_{\text{Total Costs}}, \tag{1}$$

where r_m is the average net present value of the natural gas revenue stream of a well in market m, $\widetilde{TC}_m(f_{1m}, I_m; \theta^c)$ are the total costs of connecting a fraction f_{1m} of the wells in market m to the natural gas gathering network, θ^c are parameters governing the shape of the cost function, λ is a parameter that governs the util to U.S. dollar conversion rate, and ϵ_{im} is well i's unobserved type, which represents idiosyncratic factors affecting the productivity of well i. The density $g_\epsilon(\epsilon_{im})$ captures the distribution of this well-level unobservable, which is distributed i.i.d. logistic.

The firm realizes the revenue stream from those wells that get connected to the gas-gathering network. The latter is captured by the first two terms in the profit function. In particular, the second term, with the integral, captures the fact that, among the wells in the continuum, there exists a cut-off well, characterized by $\underline{\epsilon}$. The cut-off well is special because it corresponds to the firm's marginal connection. The firm connects only those wells that are above the cut-off well in terms of their idiosyncratic productivity. On the other hand, wells characterized by $\epsilon_{im} < \underline{\epsilon}$ are not worth connecting because they would yield marginal losses for the firm.

The marginal revenue curve of the firm is decreasing. Wells in the continuum can be ordered according to their productivity type, ϵ_{im}. A firm would begin by connecting the most productive wells first. It would then proceed in descending order up to the point where the cost of connecting the marginal well equals its marginal revenue. In my model, this aspect of the choice behavior of the firm is captured by the relationship between the choice variable, f_{1m}, and the productivity of the marginal well, $\underline{\epsilon}$. Because of monotonicity of the cumulative distribution function, iff $f_{1m}^{'} > f_{1m}^{''}$, then

$$\underline{\epsilon}^{'} = G_{\epsilon}^{-1}(1 - f_{1m}^{'}) < \underline{\epsilon}^{''} = G_{\epsilon}^{-1}(1 - f_{1m}^{''}). \tag{2}$$

It follows that, in my model, connecting a larger fraction of wells is equivalent to choosing a cut-off well with a lower productivity.

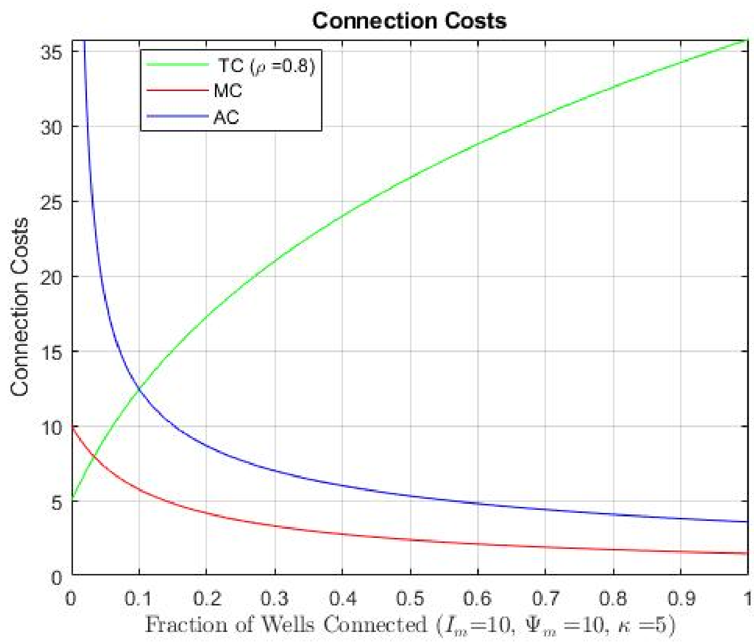

Figure 3: Costs

Note: Total costs (TC), marginal costs (MC), and average costs (AC) in a market with a single firm.

The total connection costs of the firm are given by the following cost function:

$$\widetilde{TC}_m(f_{1m}, I_m; \theta^c) = \begin{cases} \frac{1}{1-\rho}\Big[\Big(1 + f_{1m}I_m\Big)^{1-\rho} - 1\Big]\Psi_m & \text{if } \rho \neq 1 \\ \ln\Big(1 + f_{1m}I_m\Big)\Psi_m & \text{if } \rho = 1, \end{cases} \tag{3}$$

where ρ governs the curvature of the cost function, and Ψ_m governs its slope. In Figure 3, I present a graph of this total cost function with the following chosen parameter values: $\rho = 0.8$ and $\Psi_m = 10$. Figure 3 also includes the marginal and average cost functions. At the chosen value of ρ, the total costs are concave and the marginal costs are decreasing in the fraction of wells connected by the firm. In other words, at the chosen parameter values the cost function exhibits economies of scale. The cost function, however, also allows for the possibility of constant returns to scale and diseconomies of scale, depending on the value of ρ. In Figure A.5, I show some comparative statics varying ρ and Ψ_m.

Another feature of the cost function is that the size of the market does not impact the costs of connecting a given mass of wells. For example, connecting 10 percent of the wells in a a large market ($I_m = 100$) costs the same as connecting 100 percent of the wells in a small market ($I_m = 10$). This property follows form the fact that I am assuming that wells are identical in both markets up to an idiosyncratic well-error term, ϵ_{im}, which does not enter the cost function. In Figure 4, I illustrate this feature of the cost function.

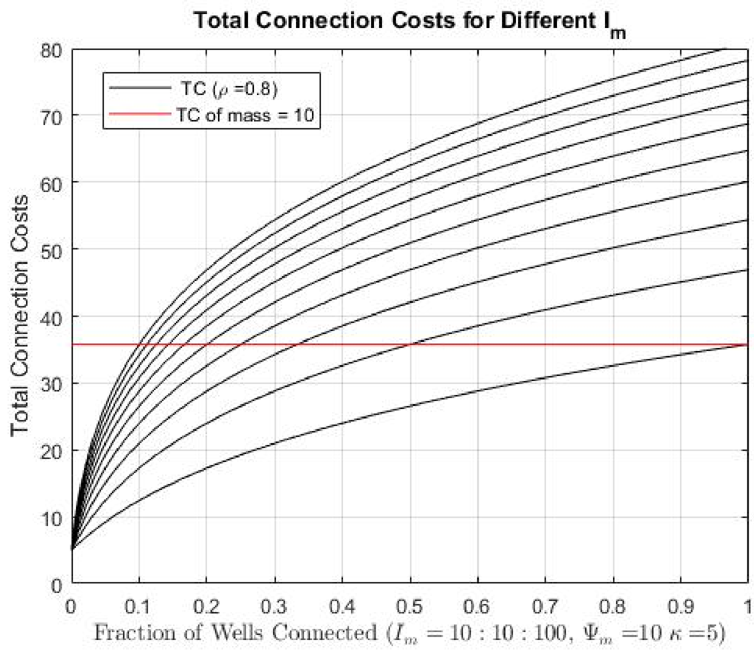

Figure 4: Comparative Statics: Varying Mass of Wells

Note: The mass of wells increases from bottom to top.

The problem of the firm is to choose what fraction of its wells to connect to the natural gas-gathering system, subject to profits being positive. The firm solves the following profit-maximization problem:

$$\max_{f_{1m} \in [0,1]} \quad \Pi_{1m}(f_{1m}) \quad \text{s.t.} \quad \Pi_{1m} > 0. \tag{4}$$

The interior solution to the problem of the firm is characterized by the following first-order condition:

$$\text{F.O.C.}[f_{1m}]: \quad \lambda r_m I_m + \frac{\partial}{\partial f_{1m}}\Big[\int_{\bar{\epsilon}=G_\epsilon^{-1}(1-f_{1m})}^{\infty} \epsilon_{im} g_\epsilon(\epsilon_{im}) d\epsilon_{im}\Big] I_m - \frac{\partial \widetilde{TC}_m}{\partial f_{1m}} = 0. \tag{5}$$

It can be shown that the optimal fraction of wells connected, f^*_{1m}, satisfies the following condition (see Section A.6):

$$f^*_{1m} = \frac{\exp(\lambda r_m - \widetilde{MC}_m(f^*_{1m}, I_m; \theta^c))}{1 + \exp(\lambda r_m - \widetilde{MC}_m(f^*_{1m}, I_m; \theta^c))}. \tag{6}$$

$\widetilde{MC}_m(f_{1m}, I_m; \theta^c)$ are the marginal costs which are given by:

$$\widetilde{MC}_m(f_{1m}, I_m; \theta^c) = \frac{\partial \widetilde{TC}_m}{\partial f_{1m}} \times \frac{1}{I_m} = \Big(1 + f_{1m} I_m\Big)^{-\rho} \Psi_m. \tag{7}$$

Equation (6) can have multiple fixed-points. Because firms maximize profits, the firm would select the fixed-point that yields the largest fraction of wells connected. I illustrate this using Figure A.6. This figure also shows the effect of market size on the fraction of wells connected. Doubling the size of the market more than doubles the mass of wells connected, as bigger firms have a larger mass of wells that are worthwhile to connect (i.e., with $\epsilon_{ij} > \underline{\epsilon}$) and can harness economies of scale further.

4.2 Cost-Sharing in Fragmented Markets with Multiple Firms

Now, I will generalize my model to incorporate strategic cooperation among multiple firms in the provision of natural gas-gathering infrastructure. In this setting, there are M markets for natural gas gathering indexed by $m \in \{1, \cdots, M\}$. In each market m, there is a continuum of symmetric wells of mass I_m.[19] Additionally, there are J_m producers, indexed by $j \in \{1, \cdots, J_m\}$, that own the wells in market m. In particular, each firm j owns a share s_{jm} of the total mass of wells in market m. I assume that the mineral right leasing and well-drilling decisions precede firms' natural gas-gathering adoption decisions. More importantly, I assume that these decisions were made with the objective of maximizing the profits from oil only. This implies that market structure is exogenous to firms' natural gas-gathering adoption decisions in my model.

As in markets with a single producer, each firm j in market m chooses what fraction, f_{jm}, of its wells to connect to the natural gas-gathering network. In markets with multiple firms, however, opportunities exist for producers to share the costs of building the natural gas-gathering system. Cost-sharing results in strategic behavior, as the connection costs become dependent on the technology adoption rates of all the firms in market m. In my model,

[19] Symmetry means that wells are drawn from the same distribution.

cost-synergies are nevertheless limited to wells within the same market. Adoption decisions in other markets do not affect firms' optimal adoption choices in market m.

The profits of firm j, in utils, from connecting a fraction f_{jm} of its wells to the gathering network are given by:

$$\Pi_{jm}(f_{jm}) = \underbrace{\lambda r_{jm} f_{jm} s_{jm} I_m + [\int_{G_\epsilon^{-1}(1-f_{jm})}^{\infty} \epsilon_{ijm} g_\epsilon(\epsilon_{ijm}) d\epsilon_{ijm}] s_{jm} I_m}_{\text{Revenues}} - \underbrace{TC_{jm}(f_m, I_m, s_m, X_m; \theta^c)}_{\text{Total Costs}}, \tag{8}$$

where r_{jm} represents the average net present value of the revenue stream of a well owned by firm j in market m, λ is a parameter that governs the util to U.S. dollar conversion rate, ϵ_{ijm} is a well-level i.i.d. logit unobservable, and $TC_j(f_m, I_m, s_m, X_m; \theta_c)$ are the total costs of connecting a fraction f_{jm} of firm j's wells in market m. The total costs depend on the entire vector of firms' connection choices, $f_m = (f_{1m}, \ldots, f_{Jm})$, a vector summarizing market m's market structure, $s_m = (s_{1m}, \ldots, s_{Jm})$, the mass of wells in market I_m, and other market-level observable characteristics, X_m. Moreover, $\theta_c = (\alpha, \beta, \kappa, \rho)$ is a vector of cost-function parameters.

Because there are multiple firms in market m, I allow for firm-level unobserved heterogeneity. I incorporate this type of heterogeneity into my model by making revenues firm-specific. In particular, I add a firm-level unobservable to the average revenue stream from wells owned by firm j in market m:

$$r_{jm} = r_m + \frac{\sigma}{\lambda}\xi_{jm}, \tag{9}$$

where ξ_{jm} is distributed i.i.d. $N(0,1)$, and σ is a parameter that governs the dispersion of ξ_{jm}.

The total costs faced by firm j in market m are given by:

$$\begin{aligned} TC_{jm}(f_m, I_m, s_m, X_m; \theta^c) &= \int_0^{f_{jm}} s_{jm} I_m \Big(1 + (z s_{jm} + \alpha \sum_{k \neq j} f_{km} s_{km}) I_m\Big)^{-\rho} \Psi_m(X_m; \beta) dz \\ &= \widetilde{TC}_m\Big((f_{jm} s_{jm} + \alpha \sum_{k\neq j} f_{km} s_{km}), I_m, X_m; \theta^c\Big) - \widetilde{TC}_m\Big(\alpha \sum_{k \neq j} f_{km} s_{km}, I_m, X_m; \theta^c\Big). \end{aligned} \tag{10}$$

The expression after the first equality sign in equation (10) represents the integral over a generalized version of the marginal cost function in "monopoly" markets. This generalized marginal cost function allows for inter-firm cost synergies. As shown by the two terms after the second equality sign in equation (10), firm j pays its contribution to the market-level costs of building a natural gas infrastructure of a given size.

Incorporating positive cost-synergies from the rest of the firms' actions results in the following marginal cost function:

$$MC_{jm}(f_m, I_m, s_m, X_m; \theta^c) = \Big(1 + (f_{jm}s_{jm} + \alpha \sum_{k \neq j} f_{km}s_{km})I_m\Big)^{-\rho} \Psi_m(X_m; \beta). \tag{11}$$

Note that this is a generalization of the marginal cost function faced by a single firm in a market, given by equation (7). Parameter ρ governs the degree of economies of scale. Nevertheless, the key parameter is α, which governs the intensity of the externalities and contains information on market contracting costs. Alpha takes values between zero and one (i.e., $\alpha \in [0, 1]$). Moreover, the limiting cases, with respect to α, of the marginal cost function are as follows:

$$MC_{jm}(f_m, I_m, s_m, X_m; \theta^c) = \begin{cases} \Big(1 + f_{jm}s_{jm}I_m\Big)^{-\rho} \Psi_m(X_m; \beta) & \text{if } \alpha = 0 \\ \Big(1 + \sum_{k=1}^{J_m} f_{km}s_{km}I_m\Big)^{-\rho} \Psi_m(X_m; \beta) & \text{if } \alpha = 1 \end{cases} \tag{12}$$

The parameter α measures the extent to which a group of firms behaves as a single entity. At one extreme, if $\alpha = 0$, it means that transaction costs are so high that firms never invest as a group. Therefore, a firm's connection choices are independent of the actions of the rest of the firms in market m. The other extreme case in which $\alpha = 1$ corresponds to the case in which firms can costlessly contract. In this case, firms behave as a single unit and can fully exploit inter-firm cost synergies. Full internalization of other firms' well connections should yield the same investment outcomes as those that would result from a single firm owning all the wells in the market. To the extent that firms are able to write contracts such that they compensate each other according to their respective contributions to the marginal cost reductions, achieving full internalization should be possible. Finally, $\alpha \in (0, 1)$ corresponds to an intermediate case in which there are transaction costs that make own-investments and investments by other firms imperfect cost complements. Because I remain agnostic about the underlying game, the parameter α is a summary parameter that measures the level of cooperation within a market with respect to a benchmark (a single firm owning every well).

In Figure 5, I present a diagrammatic two-firm example. In this example, there are two wells in a market for natural gas gathering. Each firm owns one well. Additionally, I assume that firms connect their wells to the processing plant no matter what, i.e. $f_1 = 1$ and $f_2 = 2$. These wells are so productive that it is worthwhile connecting them even if it is necessary to build separate pipelines, one for each well. Nevertheless, because the two wells are close to each other, it would be possible to connect them both using a single pipeline. If a single firm owned the wells, it would build a single pipeline, thus minimizing the costs of transporting the gas from both wells to the processing plant.

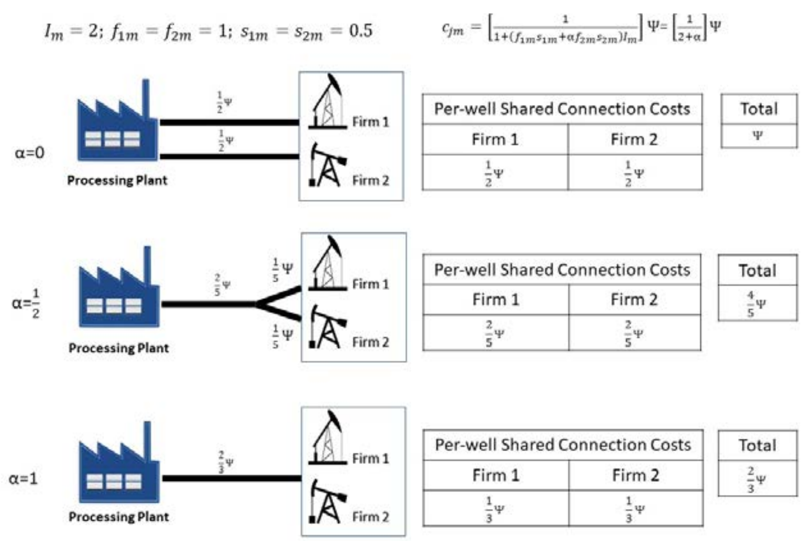

Figure 5: Example: Two Firms with One Well Each

Note: Alpha takes values between zero and one, i.e. $\alpha \in [0, 1]$.

If contracting was costless, i.e. $\alpha = 1$, the two firms would behave as if they were a single firm. This type of cooperation would result in total market-level costs equal to $\frac{2}{3}\Psi$, and firms would split these costs evenly. On the other hand, if the costs of contracting are greater than $\frac{1}{6}\Psi$, firms are better off connecting the wells individually, which results in higher costs: market-level costs equal to Ψ and firm-level costs equal to $\frac{1}{2}\Psi$. Finally, contracting costs could be positive, but less than $\frac{1}{6}\Psi$. Contracting costs in the latter range correspond to the intermediate case, where $\alpha \in (0, 1)$. This would result in inter-firm cooperation, but firms would not achieve the same costs synergies that a single producer could achieve by connecting both wells together. In Figure 5, I depict the physical manifestation of such costs for visualization purposes. Note, however, that contracting costs could be of a non-physical nature, e.g. lawyer fees to enforce contracts.

The problem of each firm j in market m is to solve the following profit-maximization problem:

$$\max_{f_{jm}\in[0,1]} \quad \Pi_{jm}(f_m) \quad \text{s.t.} \quad \Pi_{jm} > 0. \tag{13}$$

The optimal fraction of wells connected, f^*_{jm}, is characterized by the following first-order condition when the solution is interior:

$$\text{F.O.C.}[f_{jm}]: \quad \lambda(r_m + \frac{\sigma}{\lambda}\xi_{jm})s_{jm}I_m + \frac{\partial}{\partial f_{jm}}[\int_{G_\epsilon^{-1}(1-f_{jm})}^{\infty} \epsilon_{ijm} g_\epsilon(\epsilon_{ijm}) d\epsilon_{ijm}] s_{jm} I_m - \frac{\partial TC_{jm}}{\partial f_{jm}} = 0. \tag{14}$$

Firm j's first-order condition can be rexpressed as follows (see Section A.6):

$$f^*_{jm} = \frac{\exp(\lambda r_m - MC_{jm}(f^*_m, I_m, s_m, X_m; \theta_c) + \sigma\xi_{jm})}{1 + \exp(\lambda r_m - MC_{jm}(f^*_m, I_m, s_m, X_m; \theta_c) + \sigma\xi_{jm})}. \tag{15}$$

4.3 Equilibrium of the Game

In equilibrium, equation (15) is satisfied for each firm in the market simultaneously. The game can have multiple equilibria. Therefore, I solve for the Pareto-best equilibrium of the game using the best-response iteration algorithm proposed by Gowrisankaran and Stavins [2004] and spelled-out in the proof of the following proposition.

Proposition 1. *Assume that* $\frac{\partial \ -MC_{jm}}{\partial f_{km}}$ *is strictly positive,* $\forall k \in \{1, \ldots, J\}$*. Then, there exists a unique Nash equilibrium* f^P *of the connection game such that* f^P *Pareto dominates all other Nash equilibria.*

Proof. *Start with strategy profile* $f^P_0 = (1, \ldots, 1)$ *(*P^0 *for short), such that every firm in a given market connects all its wells.* P^1 *is constructed by computing the fraction of wells that earn positive profits given* P^0*. Construct* P^2 *by removing from* P^1 *the fraction of wells that earn negative profits given* P^1*. Note that* $P^2 \le P^1 \le P^0$*. Repeat until an* N *is reached such that* $P^N = P^{N+1}$*. By construction, no firm would want to unilaterally deviate from this strategy profile, and hence* P *is a Nash equilibrium. To show that* P *Pareto dominates all* *other Nash equilibria, proceed by contradiction. Suppose that there is another Nash equilibrium f^Q (Q for short) that is not Pareto dominated by P. Then, some firm must be better off under Q than under P, which implies that some firm must be connecting an additional well under Q that is not connected under P. Moreover, this implies that it is not the case that $P \geq Q$. Consider the last stage i such that $P^i \geq Q$. Such an i must exist because $P^0 \geq Q$. Consider a well w that stopped being connected between P^i and P^{i+1} but is connected under Q. Given the construction of P^{i+1}, it would be optimal for the firm that owns well w to not connect it under Q, which contradicts the assumption that Q is a Nash equilibrium.*

5 Data

To investigate the relationship between market structure and firms' investments in gathering infrastructure, I obtain well-level production data from the NDIC's website. The NDIC collects detailed monthly well-level production data, including the volume of natural gas flared and sold by each well. Information on the current operator of a well and other relevant well-level characteristics, such as each well's geographic location, is also available. Additionally, the NDIC publishes the geographic location of each of the processing plants operating in North Dakota. I also obtained historic information on who the operator of a well was at each point in time.[20]

Unfortunately, detailed data on the gathering pipeline network are not published by the NDIC.[21] In fact, the NDIC does not receive any data regarding the identity of the gatherer collecting the natural gas from a given well. Therefore, I do not observe which gathering network collects the natural gas from a connected well or the processing plant that receives it. I do, however, observe wells' natural gas sales, so I can infer whether or not a well is connected to a gathering pipeline.

I complement NDIC's data with data on Henry Hub natural gas prices taken from the Energy Information Administration's website. In table A.1, I present a list of the variables I use

[20] I requested this information from the NDIC because it is not available through the NDIC's website.

[21] These data are confidential. According to the NDCC Section 38 "The commission shall create a geographic information system database for collecting pipeline shape files as submitted by each underground gathering pipeline owner or operator. The shape files and the resulting geographic information system database are exempt from any disclosure to parties outside the commission and are confidential except as provided in this section. The information may be used by the commission in furtherance of the commission's duties." The NDIC cannot disclose this information, because doing so would subject the NDIC to a Class C felony pursuant to NDCC Section 38-08-16. These data, however, can be purchased from Rextag, a company that specializes in gathering energy infrastructure data.

in my analysis, and in section A.3 of the appendix I describe the data-gathering process in more detail.

5.1 Market Definition

To understand the data and estimate my model, I need an operational market definition. To define markets, I proceed in two steps. In the first step, I group wells according to the identity of the closest processing plant.[22] I further subdivide each of the first-step groups according to how similar wells are based on latitude, longitude, and the radian angle measure with respect to the nearest processing plant. The implicit assumption I make is that economies of scale are directional. In this second step, I use a K-means clustering algorithm, which maximizes similarities between wells in the same cluster and minimizes it between wells in different clusters.

To perform K-means clustering, the following objective function is defined:

$$J = \sum_{i=1}^{N} \sum_{k=1}^{K} r_{ik} * d(x_i, \mu_k), \tag{16}$$

where $r_{ik} = 1$ if data point x_i is assigned to cluster k, and $r_{ik} = 0$ otherwise. Moreover, μ_k represents the center of cluster k. The algorithm finds values for the $\{r_{ik}\}$ and the $\{\mu_k\}$ so as to minimize J.

I use the squared Euclidean distance as my dissimilarity measure:

$$d(x_i, x_j) = \sum_{k=1}^{p} (x_{ik} - x_{jk})^2, \tag{17}$$

where k indexes each variable, p is the total number of variables used to compute the clusters, and x_{ik} and x_{jk} are the values of the kth variable for the ith and jth well, respectively. Figure 6 presents the resulting market definition. I describe the steps of the K-means algorithm in detail in the appendix.[23]

[22] In capturing plans submitted by producers to the NDIC, there is anecdotal evidence that the wells are connected to the nearest processing plant.

[23] See Section A.4 in the appendix for a detailed description of how the algorithm works.

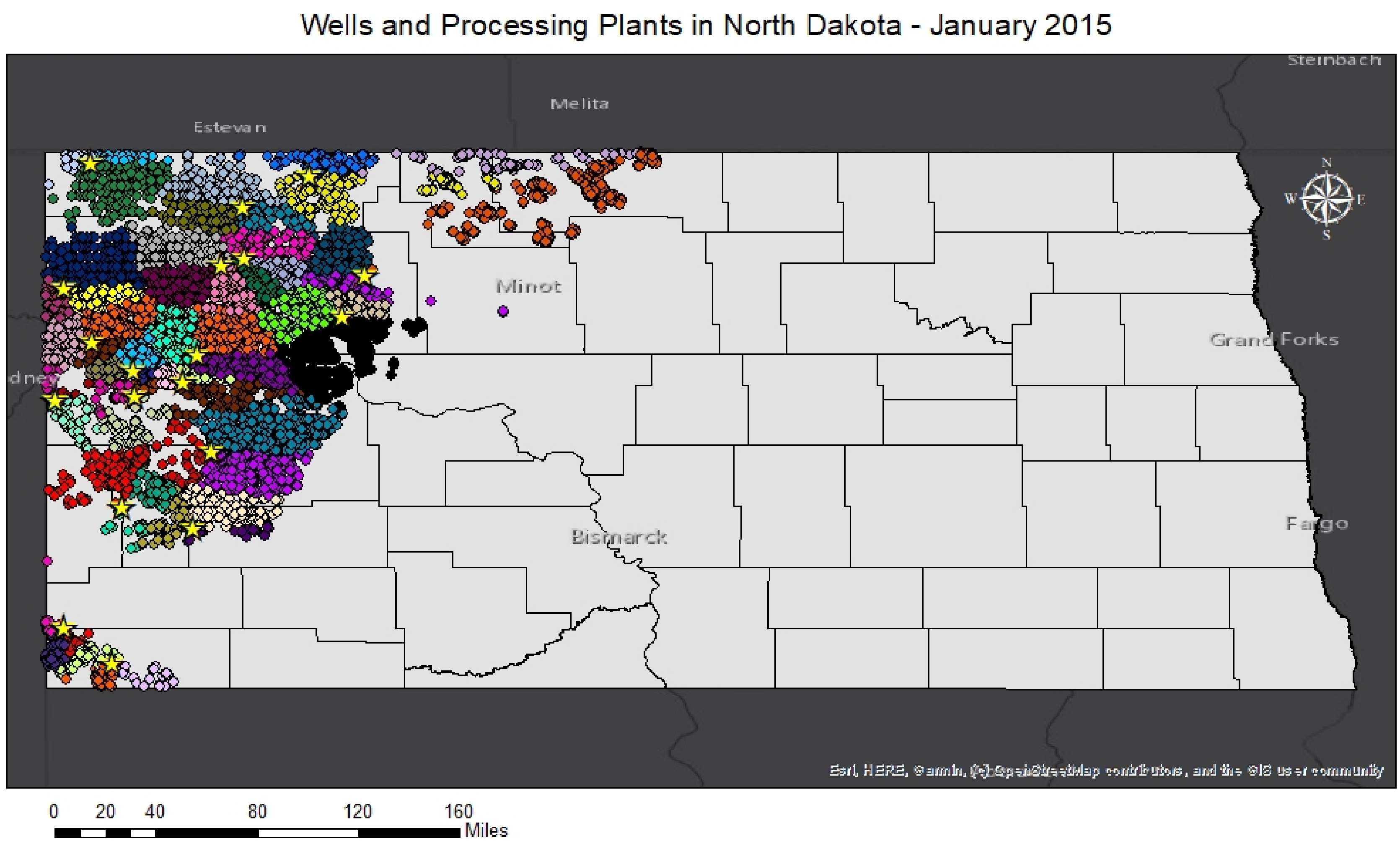

Figure 6: Market Definition

Note: Circles are wells. Each color represents a different market for natural gas gathering. Stars represent processing plants.

5.2 Natural Gas Revenue

To compute the expected net present value of a well's natural gas revenue stream, I need to describe wells' production decline curve. I follow Lade and Rudik [2019] in describing the production decline rate of wells using Fetkovich's [1980] ARPS model. According to this characterization, natural gas output at time $t+\tau$ in market m can be expressed as follows:

$$g_{m,t+\tau} = g_{mt}\tau^{\gamma}\exp(\upsilon_{m,t+\tau}), \quad \forall \tau \in \{1, ..., T\}, \tag{18}$$

where $E_t[\upsilon_{m,t+\tau}] = 0$. Lade and Rudik [2019] find $\hat{\gamma} = -0.342$.

I assume that the price of natural gas follows a random walk. I compute the expected net present value of the revenue stream of an average well in market m, r_m, as follows:

$$r_m = p_t g_{m,t} + E_t\Big[\sum_{\tau=1}^{T} p_{t+\tau} g_{m,t+\tau}\Big] = p_t g_{m,t} + p_t \sum_{\tau=1}^{T} E_t[g_{m,t+\tau}] = \\ p_t g_{m,t} + p_t \sum_{\tau=1}^{T} \hat{g}_{m,t+\tau} = p_t g_{m,t}\Big[1 + \sum_{\tau=1}^{T} \tau^{\hat{\gamma}}\Big]. \tag{19}$$

The second equality follows from the assumption that firms are unresponsive at the intensive margin to hydrocarbon prices (i.e., they only respond at the extensive margin by adjusting drilling intensity). This a common assumption in the literature (Anderson et al. [2014]).[24] The implication is that the natural gas production of a given well is independent from the price of natural gas. The third equality follows from replacing the expected value with the predicted value. I use a twenty year time-horizon.

5.3 Market-level Descriptive Statistics

In Table 1, I present some market-level summary statistics of my data. As can be observed, a market has, on average, 11.09 firms and 194.96 wells. Moreover, the level of well-ownership concentration, as measured by the Herfindahl-Hirschman Index (HHI), varies greatly between markets, ranging from 0.100 to 0.873. Similarly, the fraction of wells connected at the market

[24] Anderson et al. [2014] show that production from existing wells in Texas does not respond to prices.

(M=57)	Mean	Std. Dev.	Min	Max
Area of Market in Square Miles	74.51	97.73	0.69	531.75
Number of Firms	11.09	5.67	2.00	29.00
HHI (Wells)	0.304	0.164	0.100	0.873
HHI (Natural Gas Output in MCF)	0.395	0.212	0.138	0.976
Fraction of Firms Connected	0.836	0.194	0.103	1.000
No. of Wells	194.96	190.87	11.00	939.00
Fraction of Wells Connected	0.854	0.195	0.045	1.000
No. of Wells per Square Mile	10.08	33.55	0.20	252.31
MCF Gas	753,591.3	1,187,259.0	4,417.0	5,929,056.0
Fraction of Gas Flared	0.269	0.189	0.031	0.803
Miles to Nearest Processing Plant	11.189	9.875	3.569	63.332
Average Miles from Wells to Nearest Processing Plant	12.157	9.774	4.216	63.702

Note: Markets were defined by clustering wells active in North Dakota in January 2015 as follows. First, wells were grouped according to the identity of the nearest processing plant active in January 2015. Next, each of these groups of wells was further clustered into three subgroups using its radian angle measure with respect to the nearest processing plant, and its geographic location as given by latitude and longitude. To do the latter, I used a k-means algorithm with K = 3. A well is classified as connected to the gas-gathering network if it has sold some positive volume of gas at least once since it was drilled. The midpoint of a market was computed using the methods described in http://www.geomidpoint.com/calculation.html

Table 1: Market-level Descriptive Statistics (January 2015)

level varies significantly between markets, ranging from markets where almost none of the wells are connected to those where all of the wells are connected. Similarly, the fraction of firms within a market that connect at least one of their wells varies extensively across markets, ranging from markets in which only ten percent of the firms have connected at least one well to markets where all of the firms have connected at least one of their wells. Not surprisingly, therefore, the percent of gas flared also varies greatly across markets.

5.4 Descriptive Evidence

5.4.1 Market-level Evidence

In Figure 7, I present a scatter plot showing the relationship of the market's Herfindahl-Hirschman index (HHI), which I compute using the share of wells owned by each producer in a market, and the market level fraction of wells connected. In Table 2, I look at this relationship using market-level regression analysis. Table 2 contains estimates of the coefficients of a linear regression of the fraction of wells connected in a market for gas gathering on the market's HHI. Additionally, I control for the distance from the market centroid to the nearest processing plant, market well density, and the number of wells in each of the markets. The results of this exercise suggest that transaction costs contribute to under-adoption of natural gas capturing infrastructure, relative to a market where a single firm owns all the wells.

The coefficient estimates of the regressions in Table 2 have the expected sign. These results suggest that a market in which a single firm owns all the wells (HHI = 1) is associated with a 26.3-44.1 percentage point increase in well connections compared to a market in which the share of wells owned by each firm approaches zero (HHI = 0).

The positive correlation between market concentration and the fraction of wells connected in a market could be explained as follows. A decrease in the number of firms operating a given set of wells in a market could reduce the number of contracts needed for reaching a cooperation agreement for building gas-gathering infrastructure. Moreover, reaching an agreement on how to share the surplus that results from this cooperation could become easier when fewer firms are involved in the negotiations. This type of transaction cost savings could result in higher levels of infrastructure investment and would explain the relationship I find in the data. As expressed in a report by Carbon Limits AS, "this tendency for unitization of activities within an area by a single operator could help reduce flaring of associated gas, as coordination among different, neighboring well operators to develop gas gathering infrastructure increases" (Pederstad [2015]).

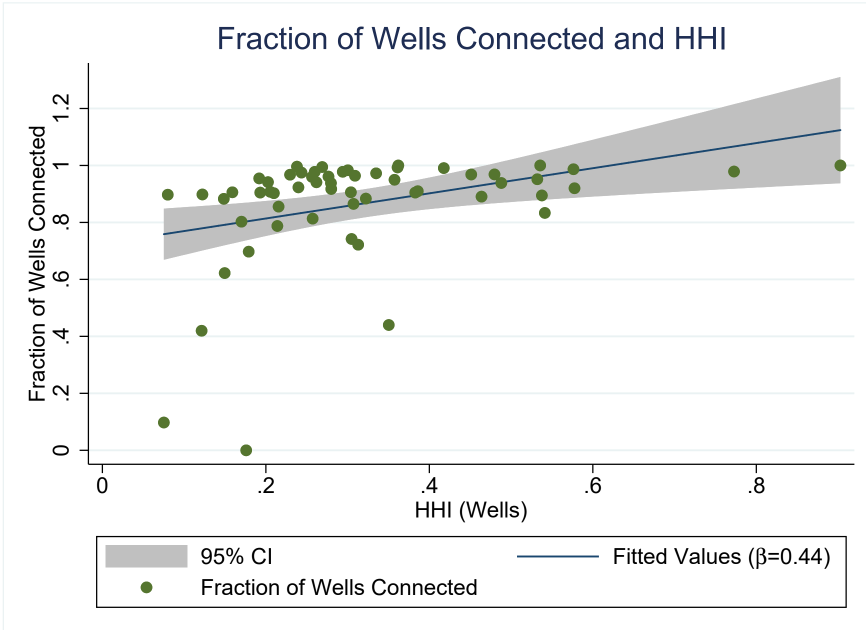

Figure 7: Fraction of wells connected and HHI

Note: The HHI is computed using the share of wells owned by a given firm in a market.

Dependent Variable: Fraction of Wells Connected

Market HHI (Wells)	0.441**	0.252**	0.299***	0.263**
	(0.166)	(0.102)	(0.105)	(0.102)
Miles to Processing Plant (Hundreds)		-1.083***	-1.090***	-1.097***
		(0.221)	(0.222)	(0.215)
Number of Wells in Market (Thousands)			0.207	0.221
			(0.214)	(0.214)
Well Density (Thousand Wells per Sq. Mile)				3.419
				(2.947)
Constant	0.726***	0.928***	0.873***	0.864***
	(0.0726)	(0.0437)	(0.0697)	(0.0702)
Observations	57	57	57	57
R-squared	0.130	0.510	0.523	0.537

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 2: OLS Regression of Fraction of Wells Connected (January 2015)

The sign of the point estimate corresponding to the number of wells in a market is positive, as we would have expected if there are scale economies. Interestingly, however, this coefficient is not statistically different from zero at the standard significance levels. This could suggest that there are contracting frictions, preventing firms from harnessing economies of scale jointly at the market level, while they still are able to harness them at the firm level. Also, the distance from a market's geographic midpoint to the nearest processing plant is negatively correlated with the fraction of wells connected in a market. This is expected because transportation costs are increasing with distance. Finally, the point estimate of the well density coefficient is positive as expected because it is easier to connect wells that are close to each other.

Dependent Variable: Market-level Fraction of Natural Gas Output Flared

VARIABLES	(1) Model 1	(2) Model 2	(3) Model 3	(4) Model 4
Market HHI (Wells)	-0.214***	-0.181**	-0.187**	-0.165**
	(0.0774)	(0.0689)	(0.0781)	(0.0779)
Miles to Processing Plant (Hundreds)		0.328***	0.324***	0.300**
		(0.103)	(0.113)	(0.116)
Number of Wells in Market (Thousands)			-0.0298	-0.0494
			(0.143)	(0.152)
Well Density (Thousand Wells per Sq. Mile)				-4.913
				(4.119)
Constant	0.301***	0.242***	0.251***	0.274***
	(0.0335)	(0.0363)	(0.0667)	(0.0774)
Observations	50	50	50	50
R-squared	0.054	0.184	0.185	0.207

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 3: OLS Regression of Fraction of Natural Gas Output Flared (January 2015)

In Table 3, I show results of a regression similar to the one in Table 2, except that the dependent variable is the fraction of natural gas output flared at the market level. As expected, because more well connections result in more natural gas being captured, the relationship between market concentration and flaring is negative, and the relationship between the distance from the market centroid and flaring is positive. The coefficient corresponding to the number of wells in a market remains statistically indistinguishable from zero, although it does displays a negative sign as expected. Finally, the well density coefficient is also negative.

In Table A.2, I present results of a similar regression, where the dependent variable is the volume of natural gas flared at the market level. Further, in Table A.3, I present a similar regression on the fraction of wells connected, where I compute the HHI using the share of natural gas output produced by each firm.

5.4.2 Well-level Evidence

So far, I have presented market-level evidence suggesting that market-structure matters when it comes to connecting wells and reducing flaring. Now, I present additional evidence using well-level data. In Table 4, I present several specifications of a regression of an indicator variable, which equals zero if the well is not connected and one otherwise, on a measure of ownership concentration in the well's market, the number of wells owned by the firm operating the well in the market, and various other control variables. The advantage of using well-level data is that I can include firm-level fixed effects to control for firm-level unobservables.

Again, the signs of all coefficient estimates are all as expected. According to these regression results, market concentration is associated with a higher likelihood of a well being connected to the natural gas-gathering network. According to the regression results in Table 4, the probability of a well being connected to the gas-gathering network is 13.1-24.1 percentage points higher in a market where a single firms owns all the wells (HHI = 1) vis-à-vis a market in which well ownership fragmentation is extreme (HHI = 0). In contrast to the market-level results in Table 2, the coefficient estimates corresponding to the number of wells are statistically significant.

In column (6) of Table 4, I present the estimates of the model that includes firm-level fixed effects. The reason that the coefficient becomes less significant is probably due to the fact that I only have a limited number of markets, and not every firm is active in all of the markets. Because I am including firm fixed-effects, I am only using within-firm variation. To get more precise estimates of the effect of HHI on the likelihood of a well being connected, I would need more within-firm variation.

Dependent Variable: Dummy = 1 if Well is Connected

VARIABLES	(1) OLS	(2) OLS	(3) OLS	(4) OLS	(5) OLS	(6) Firm FE	(7) Logit MFX
Firm Wells (Thousands)	1.147***	0.957***	0.559***	0.683***	0.643***	0.333**	0.657***
	(0.0495)	(0.0508)	(0.0490)	(0.0497)	(0.0492)	(0.131)	(0.0659)
Market HHI (Wells)		0.241***	0.225***	0.131***	0.168***	0.144*	0.199***
		(0.0208)	(0.0197)	(0.0214)	(0.0218)	(0.0857)	(0.0297)
Miles Mkt to PP			-1.262***	-1.250***	-1.228***	-0.955***	-0.547***
			(0.0206)	(0.0198)	(0.0198)	(0.200)	(0.0289)
Market Area (Acres)				-0.139***	-0.115***	-0.0769***	-0.0579***
				(0.0109)	(0.0111)	(0.0254)	(0.00860)
Gas Output					0.00568***	0.00300***	0.00959***
					(0.000469)	(0.000827)	(0.00141)
Constant	0.779***	0.725***	0.930***	0.983***	0.944***	0.937***	
	(0.00585)	(0.00806)	(0.00773)	(0.00904)	(0.0100)	(0.0481)	
Observations	11,113	11,113	11,113	11,113	11,113	11,113	11,113
R-squared	0.038	0.046	0.287	0.299	0.309	0.106	
Number of Firms						121	

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table 4: Regression of “Well Connected” Indicator Variable

6 Estimation, Identification, and Results

6.1 Structural Model Estimation

I describe here the procedure I use to estimate the parameters of the technology adoption cost-sharing game. The main goal of my estimation exercise is to measure inter-firm contracting costs. I estimate my structural model using the Method of Simulated Moments (MSM) introduced by McFadden [1989] and Pakes and Pollard [1989]. The estimation algorithm includes an outer loop, which searches over the parameter space, and an inner loop, which selects the Pareto-best equilibrium, as in Gowrisankaran and Stavins [2004] and Ackerberg and Gowrisankaran [2006].

I start by drawing a matrix $\widehat{\xi}$ of simulated firm-level unobservables of dimensions $S \times N$, where S represents the number of simulated draws of the firm-level unobservable, ξ_{jm}, N is the sample size, and each element of this matrix, ξ^s_{jm}, is drawn from a $N(0,1)$ distribution. Note that each observation in my dataset corresponds to a given firm j in a given market m, and the observations corresponding to each market have been stacked on top of each other. Once it has been drawn, the matrix $\widehat{\xi}$ remains unaltered throughout the rest of the estimation algorithm.

The outer loop of the estimation algorithm searches over the parameter space. Therefore, within each iteration of this outer loop, the parameter vector, $\theta = (\theta_c, \theta_{-c})$, and the simulated error matrix, $\widehat{\xi}$, are given. It follows that I can compute the predicted (by my model) firm-level fraction of wells connected, given by (15), for each draw of the firm-level unobservable, ξ^s_{jm}, and chosen values of f_m. Hence, I can start the best-response iteration algorithm by evaluating equation (15) at $f_m = (1, \ldots, 1)$, conditional on the within-outer-loop parameter values and ξ^s_{jm}. This inner loop yields the predicted Pareto-best equilibrium fraction of wells connected, which satisfies the following fixed-point equation for all firms in a market:

$$\widetilde{f}_{jm} = h(\widetilde{f}_m, I_m, s_m, r_m, X_m, \xi^s_{jm}; \theta). \tag{20}$$

After computing $\widetilde{f}_{jm}$, I can use the sample analog, $\tilde{G}_N(\theta)$, of the following moment condition to recover estimates of the parameters of my model:

$$G_N(\theta) = E\left[\begin{matrix}(f_{jm} - E[h(\tilde{f}_m, I_m, s_m, r_m, X_m, \xi^s_{jm};\theta)|z_{jm};\theta]) \otimes \begin{pmatrix}1\\ z_{jm}\end{pmatrix}\\ (f^2_{jm} - E[h(\tilde{f}_m, I_m, s_m, r_m, X_m, \xi^s_{jm};\theta)^2|z_{jm};\theta])\end{matrix}\right] = 0 \quad \text{at } \theta = \theta^0, \tag{21}$$

where z_{jm} is a $K \times 1$ vector of firm-market-level variables, including the share of wells owned by firm j in market m, the total number of wells in market m, the number of firms operating in market m, the market average of the NPV of wells' natural gas revenue stream in market m, the concentration of wells not owned by firm j in market m as measured by the HHI, and market-level characteristics, such as the distance from the centroid of market m to the nearest processing plant and area of the market.

The outer loop search procedure finds the MSM estimate of θ satisfying

$$\hat{\theta} = \arg\min_{\theta} \tilde{G}_N(\theta)' A \tilde{G}_N(\theta), \tag{22}$$

where $A = Var(\tilde{G}_N(\theta))^{-1}$. I use the Continuously Updating Estimator (CUE) to find $\hat{\theta}$.

6.2 Identification

The parameter measuring contracting costs, α, is identified from variation in market structure. The intuition is that variation in the fraction of wells connected across observationally equivalent markets, except for market structure, contains information on inter-firm contracting costs. This intuition can be best explained using Table 5.

In Table 5, I present a simulation of my model while varying both market structure, by increasing the number of firms in a market, and the parameter α. Markets are identical in terms of the mass of wells. I fix the mass of wells equal to 100 in all markets. The only difference is that in markets with more than one firm, these wells are divided in equal proportions among the firms. Therefore, in a market with two firms, each of them owns 50 wells; in a market with five firms, each of them owns 20 wells; and in a market with ten firms, each of them owns 10 wells.

As observed in Table 5, as α goes to one, the behavior of a firm in an ownership-fragmented market approaches the behavior of a firm that owns every well in a market with a mass of wells equal to 100. On the other hand, when α equals zero, the behavior of a firm corresponds to the behavior of a single firm in a market with a smaller mass of wells equal to $100/J_m$, where J_m is the number of firms in the market. Moreover, each column corresponding to values of $\alpha \in (0, 1)$ in Table 5 also displays a unique pattern as the number of firms increases. In other words, the way in which the fraction of wells connected by the firms changes as market structure changes, identifies α.

$\alpha =$	0	0.2	0.4	0.6	0.8	1
Fraction Connected						
One Firm	0.7174	0.7174	0.7174	0.7174	0.7174	0.7174
Two Firms	0.7033	0.7081	0.7114	0.7139	0.7159	0.7174
Five Firms	0.6564	0.6921	0.7044	0.7108	0.7148	0.7174
Ten Firms	0.5618	0.6793	0.7009	0.7095	0.7144	0.7174
Total Mass Connected						
One Firm	71.74	71.74	71.74	71.74	71.74	71.74
Two Firms	70.33	70.81	71.14	71.39	71.59	71.74
Five Firms	65.64	69.21	70.44	71.08	71.48	71.74
Ten Firms	56.18	67.93	70.09	70.95	71.44	71.74

Note: $\rho = 1$; $\sigma = 1$; $\Psi_m = 500$; $I_m = 100$; $r_m = 50$

Table 5: Market Structure and the Transaction Cost Parameter

The economies of scale parameter, ρ, is identified from variation in market size (i.e., the mass of wells in each market). Heuristically, the following argument can be made. For each value of ρ, it is possible to identify α as discussed in the previous subsection. Each combination of ρ, and the corresponding α, yields a unique pattern of firm behavior as the market size varies.

Equilibrium selection is an alternative explanation for under-adoption of natural gas gathering pipelines when there are multiple equilibria. Because under-investment can result from selection of an equilibrium other than the Pareto-best, I enforce selection of the Pareto-best equilibrium.

6.3 Parameter Estimates

In Table 6, I present my main estimation results. According to these results, the cost function exhibits economies of scale. Additionally, my results suggest that contracting costs prevent firms from fully achieving economies of scale in fragmented markets. Economies of scale follow from the fact that the estimate of the parameter governing the curvature of the cost function, $\hat{\rho}$, is strictly greater than zero: $\hat{\rho} = 0.9449$.

	(1) Estimates	(2) Standard Errors
$\hat{\alpha}$	0.5896	TBD
$\hat{\rho}$	0.9449	TBD
$\hat{\beta}_1$	28428.9718	TBD
$\hat{\sigma}$	2.6015	TBD
$\hat{\lambda}$	0.1108	TBD

Note: β_1 corresponds to market distance.

Table 6: Parameter Estimates - January 2015

Contracting costs results from the fact that my estimate of alpha is strictly smaller than one: $\hat{\alpha} = 0.5896$. This means that wells owned by other firms in the same market achieve only 59 percent of the marginal cost reductions that wells owned by the firm itself achieve. I interpret this 31 percent difference in the intensity of cost synergies between the wells owned by a firm and the wells owned by other firms in the market as a measure of contracting costs.

Given my parameter estimates, I can compute the predicted marginal cost function. For a market with a single firm and using the average market size and average distance from a market's centroid to the nearest processing plant, the predicted marginal cost function is as follows:

$$\widehat{\widehat{MC}}_m = (1 + f_{1m} \times \overline{I}_m)^{-\hat{\rho}} \times \hat{\beta}_1 \times \overline{\text{Miles Mkt to PP}}$$
$$= (1 + f_{1m} \times 194.9649)^{-0.6538} \times 4694.4294 \times 11.18912. \quad (23)$$

In Table 7, I present the estimated marginal cost function evaluated at different points for a market with 100 wells in the second column and for a market of the average size in my data in the fifth column.

	$I_m = 100$			Average Market ($\bar{I}_m = 194.9649$)		
	(1)	(2)	(3)	(4)	(5)	(6)
f_{1m}	$f_{1m}I_m$	MC_m	%Δ	$f_{1m}I_m$	MC_m	%Δ
0	0	$2,870,895.10	-	0	$2,870,895.10	-
0.01	1	$1,491,331.12	0.00%	1.95	$1,033,073.76	-30.73%
0.1	10	$297,855.33	-80.03%	19.50	$165,428.90	-88.91%
0.2	20	$161,678.52	-89.16%	38.99	$87,963.57	-94.10%
0.3	30	$111,899.89	-92.50%	58.49	$60,443.40	-95.95%
0.4	40	$85,920.71	-94.24%	77.99	$46,240.49	-96.90%
0.5	50	$69,909.19	-95.31%	97.48	$37,539.85	-97.48%
0.6	60	$59,028.15	-96.04%	116.98	$31,649.68	-97.88%
0.7	70	$51,140.30	-96.57%	136.48	$27,391.03	-98.16%
0.8	80	$45,153.33	-96.97%	155.97	$24,164.91	-98.38%
0.9	90	$40,450.05	-97.29%	175.47	$21,634.24	-98.55%
1	100	$36,655.07	-97.54%	194.96	$19,594.67	-98.69%

Note: %Δ is the percentage decrease in marginal costs w.r.t. $f_1 I_m = 1$.

Table 7: Marginal Costs - Single Firm in a Market

7 Counterfactual Firm Behavior

In this section, I investigate counterfactual firm behavior and the losses faced by producers from limited cooperation.

7.1 Counterfactual Adoption

I begin by computing a counterfactual in which I investigate well connections as the parameter α goes to one. In other words, I compute what the investment outcome would be if inter-firm contracting was costless or if all the wells in each of the markets were owned by a single producer. In Table 8, I present the results of this exercise. Letting α go to one results in 131 additional well-connections.

As it is possible to observe in Table 8, most of the additional connections occur in highly fragmented markets (i.e., markets in which the HHI concentration measure lies between 0 and 0.2). Of the 131 additional well connections, 102 occur in these highly fragmented markets. Conversely, in highly concentrated markets, changing α has almost not effect in terms of additional well connections. In markets in which the HHI is greater that 0.7, letting α go to one results only in one additional connection.

(1) HHI	(2) Wells	(3) Connected	(4) Predicted Change	(5) Predicted Connected ($\alpha = 1$)
0-0.2	4,693	3,706	103	3,809
0.3-0.4	5,024	4,607	20	4,627
0.5-0.6	1,116	1,015	7	1,022
0.7-1	193	177	0	177
0.9-1	87	86	1	87
Total (Jan-15)	11,113	9,591	131	9,722

Note: Column (3) presents counterfactual connections.

Table 8: Predicted Number of Wells Connected ($\alpha = 1$)

7.2 Change in Producer Surplus

I can use my model to compute the change in producer surplus. Frictionless contracting would enable firms to connect wells at a lower marginal cost. In Figure 8, I illustrate this as well as the corresponding loss in producer surplus from additional contracting costs in fragmented markets.

$$\Delta PS_{jm} = \int_0^{f_{jm}^{\alpha=1}} \Big[MC_{jm}(t;\alpha=\hat{\alpha}) - MC_{jm}(t;\alpha=1)\Big] s_{jm} I_m dt \\ + r_{jm}(f_{jm}^{\alpha=1} - f_{jm}^{\alpha=\hat{\alpha}}) s_{jm} I_m - \Big[\int_{G_\epsilon^{-1}(1-f_{jm}^{\alpha=1})}^{G_\epsilon^{-1}(1-f_{jm}^{\alpha=\hat{\alpha}})} \epsilon_{ijm} g_\epsilon(\epsilon_{ijm}) d\epsilon_{ijm}\Big] s_{jm} I_m \quad (24)$$

In equation (24), I present the expression for the loss in producer surplus from market fragmentation. I find that the total loss in producer surplus is \$371,640,000.

7.3 Flaring Penalty

In this section I compute the flaring penalty that would approximate the single-firm efficiency benchmark.

When firms face a penalty per unconnected well, ϕ, their profit function can be expressed as follows:

$$\Pi_{jm}(f_{jm}) = \lambda r_{jm} f_{jm} s_{jm} I_m + [\int_{G_\epsilon^{-1}(1-f_{jm})}^{\infty} \epsilon_{ijm} g_\epsilon(\epsilon_{ijm}) d\epsilon_{ijm}] s_{jm} I_m$$
$$- TC_{jm}(f_m, I_m, s_m, X_m; \theta^c) - (1 - f_{jm}) s_{jm} I_m \phi. \quad (25)$$

The penalty that approximates the single-firm efficiency benchmark satisfies

$$\phi^{opt} = \arg\min |f^{\alpha=1} - f^{\alpha=\hat{\alpha},\phi}|. \quad (26)$$

In other words, I search for the penalty that better approximates the investment outcome that would prevail if a single firm owned all the wells in each market. I find $\phi^{opt} = \$2,555$ USD per unconnected well.

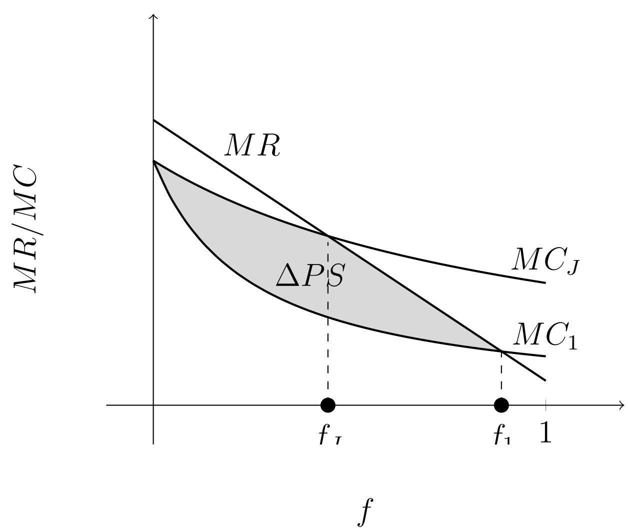

Figure 8: Potential Loss in Producer Surplus

Note: I assume there is a continuum of wells in a market for natural gas gathering. The x-axis corresponds to the fraction of wells connected in a market for natural gas gathering, f. The y-axis represents the marginal revenue and marginal cost of increasing the fraction of wells connected in a given market. The marginal revenue is constant, as I assume that wells are symmetric, and North Dakota's natural gas output represents only a small share of the US market. On the other hand, the marginal cost in the relevant region is increasing. Marginal cost curve MC_1 corresponds to the case in which a single firm owns all the wells in the market. Marginal cost curve MC_J corresponds to the case in which J firms own the mass of wells in the market. As external economies of scale approach internal economies of scale (α goes to one) a market with J firms behaves as a market operated by a single firm.

8 Conclusion

Coase [1937] argued that production will be organized within a firm as long as it costs less to do so than through the market. Ronald Coase's insights were further developed by Williamson [1975, 1979, 1985], Klein et al. [1978], and others, giving rise to transaction cost economics (TCE). According to TCE, *hierarchical governance* structures, such as the firm, are more efficient than markets for organizing transactions that involve specific investments and occur in an uncertain environment. In this paper, I present empirical evidence suggesting that there are cost advantages to organizing natural gas-gathering within a firm rather than through the market. Additionally, I estimate counterfactulas to examine what policies might be applied to multiple firms contracting in a market such that they approach the behavior of a single firm market.

In my analysis, I use data on producers' well-connection decisions in North Dakota to study the relationship between market fragmentation and collective investment decisions by firms. My results show that well-ownership structure impacts market-level pipeline adoption. I find that there are inter-firm contracting costs, which make it more costly for firms to achieve economies of scale in fragmented markets. In particular, I find a 41 percent difference between the intensity of cost synergies from wells owned by a firm and those owned by others. I interpret this difference as a measure of contracting costs. To establish whether these inter-firm contracting costs result in under-investment, I compute counterfactual adoption rates consistent with costless contracting. I find evidence of under-adoption. Namely, if all wells in each market were owned by a single producer, 131 additional wells would be connected to the natural gas-gathering network. Most of the additional counterfactual connections occur in highly fragmented markets.

While my findings suggest that market fragmentation results in under-adoption of natural gas gathering technology, further research should contrasts these costs againsts the benefits of multi-firm development of oil and gas plays.

A Appendix

A.1 Additional Figures

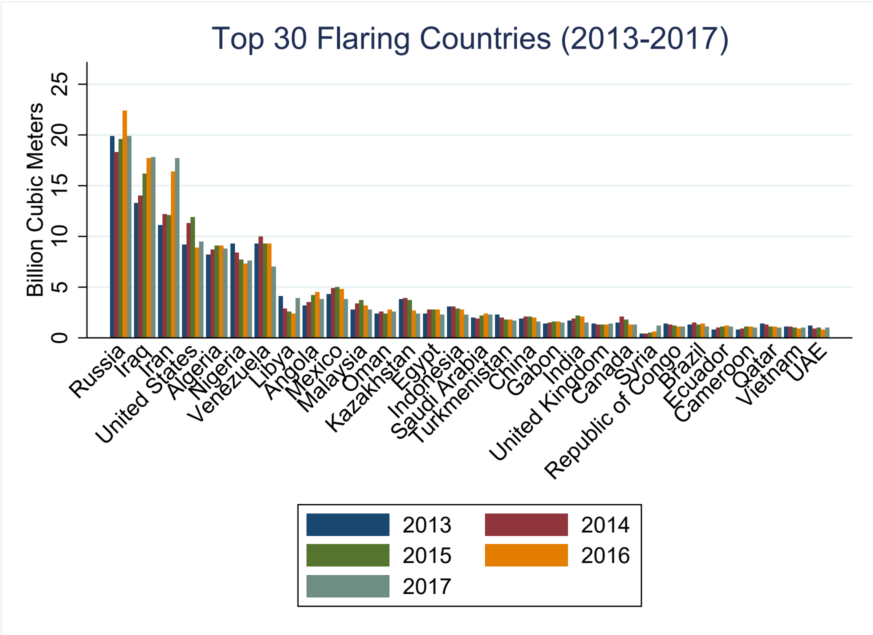

Figure A.1: Top 30 Flaring Countries (2013-15)

Data Source: http://www.worldbank.org/content/dam/photos/419x440/2016/oct/flaring_data.JPG

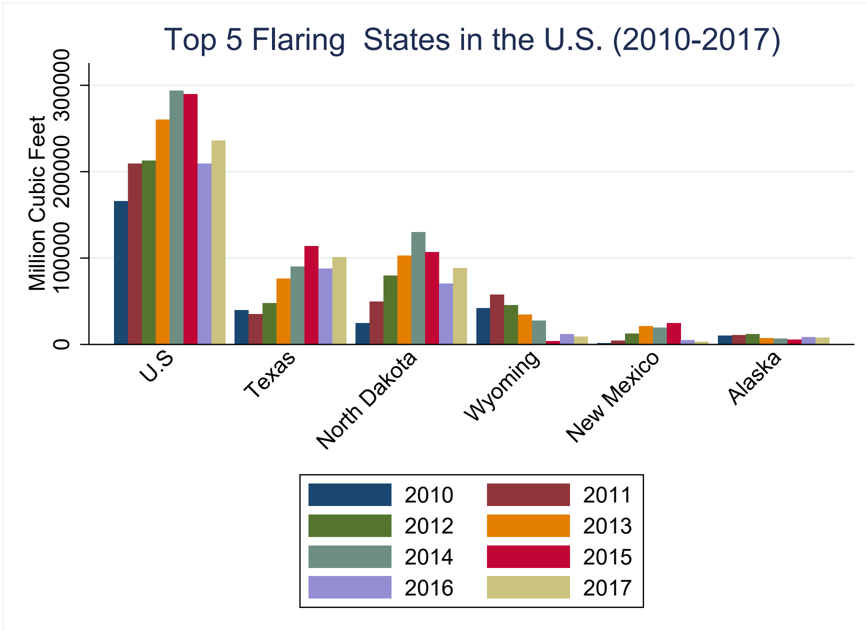

Figure A.2: Top 5 Flaring Sates in the United States (2010-15)

Data Source: https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGV_mmcf_a.htm

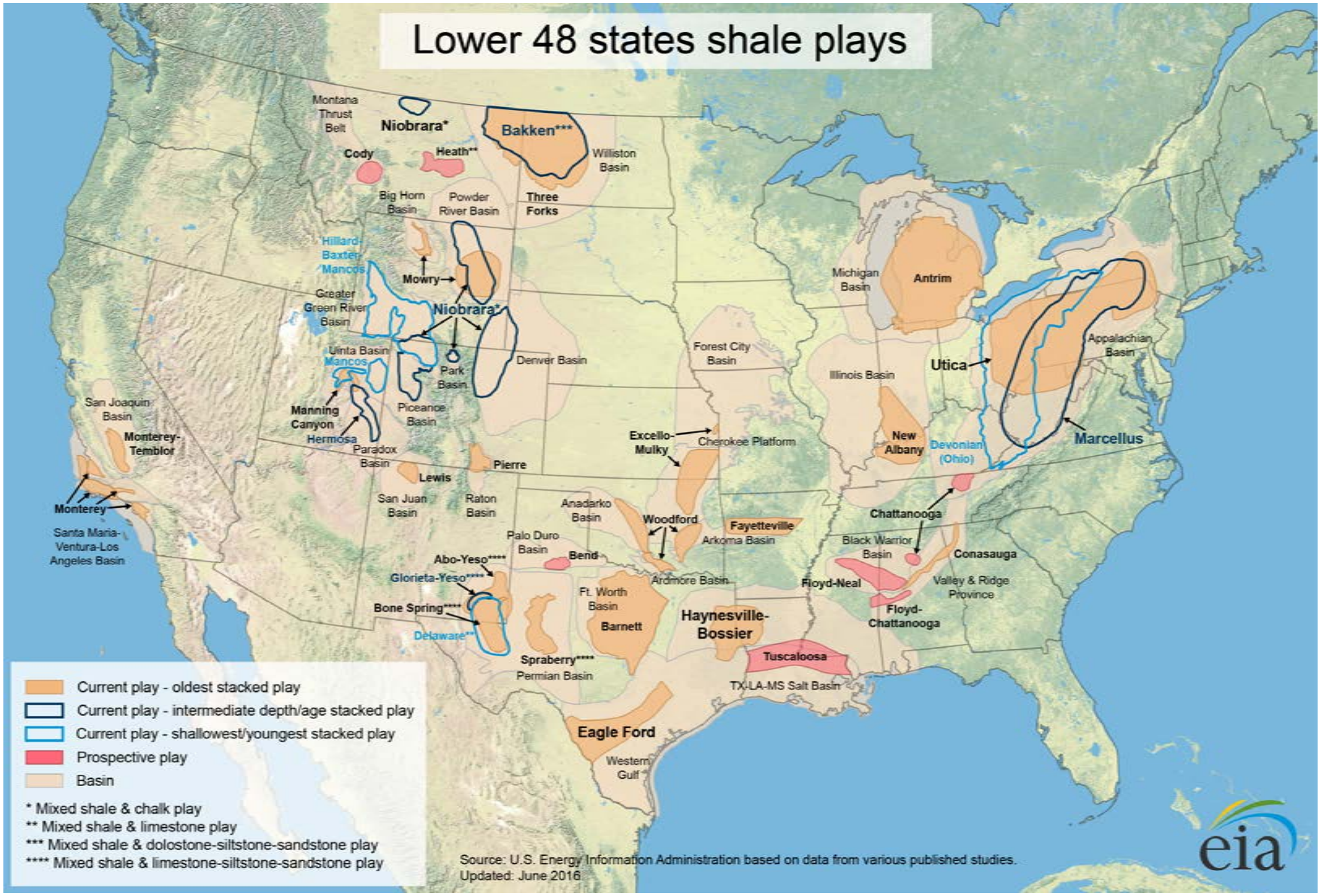

Figure A.3: Oil and Gas Production in North Dakota and Prices

Source: https://www.eia.gov/maps/images/shale_gas_lower48.jpg

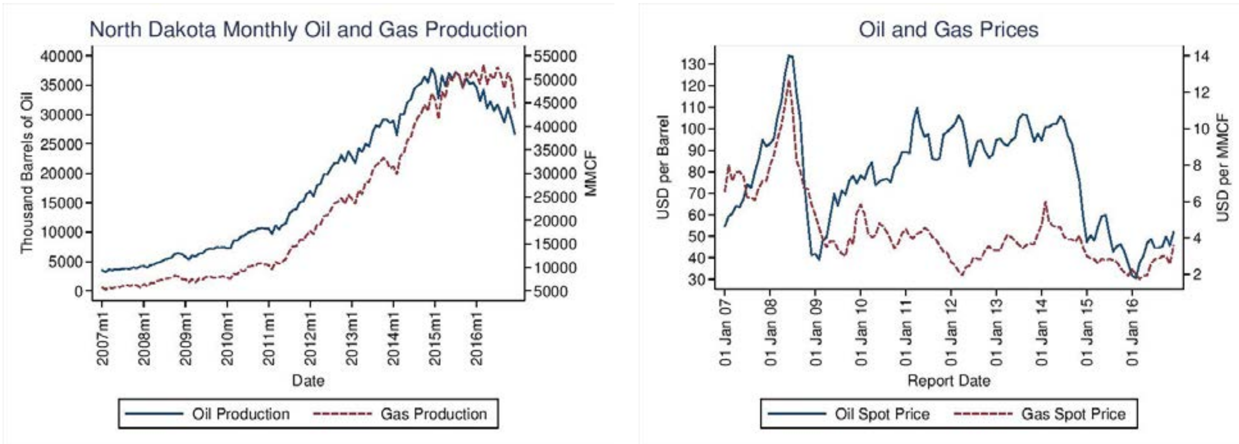

Figure A.4: Lower 48 states shale plays

Note:

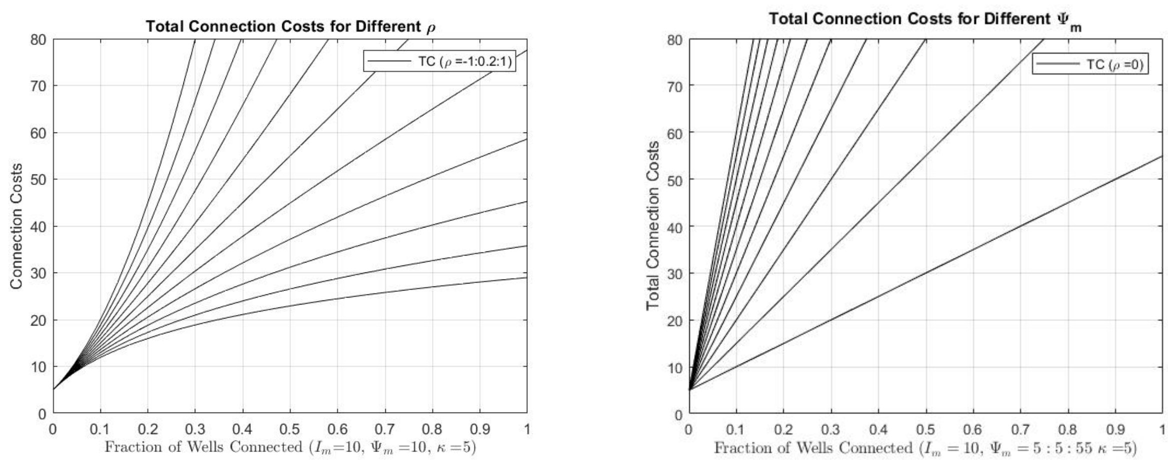

Figure A.5: Comparative Statics

Note: The left panel shows comparative statics varying ρ, while the right panel shows comparative statics varying Ψ_m. Left panel: ρ increases in intervals of 0.2 from top to bottom starting at -1 and ending at 1. Right: Ψ_m increases in intervals of 5 from bottom to top starting at 5 and ending at 55.

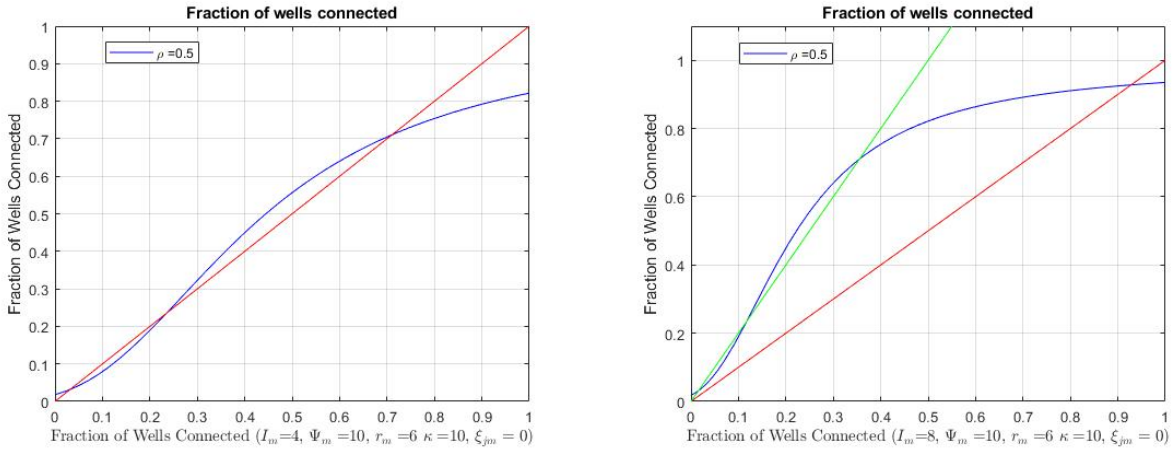

Figure A.6: Fraction of Wells Connected by a Single Producer in the Market

Note: The left panel plots equation (6) for a market with a mass of four wells in blue and a 45 degree diagonal in red. As can be observed in the figure, equation (6) has three fixed-points. Because we believe firms are profit-maximizers, the firms chooses to connect the fraction of wells corresponding to the fixed-point further to the right. The right panel illustrates the effect of doubling the size of the market. This panel plots equation (6) for a market with a mass of eight wells in blue and a 45 degree diagonal in red. The intersections of the red and blue lines correspond to the fixed-points in the larger market. The right panel also includes a 77.5 degree diagonal, which intersects the graph of equation (6) at the fixed-points corresponding to the smaller market. Note that doubling the market size more than doubles the mass of wells connected.

A.2 Additional Tables

Variable	Description
Gas Output	Monthly natural gas output in million cubic feet (MCF).
Gas Flared	Monthly volume of flared natural gas in MCF.
Well Connected	Indicator variable equal to one if a well has had natural gas sales at any point in time since its completion.
Gas Price	Spot price in MCF per dollar based on delivery at the Henry Hub in Louisiana.
Operator ID	Identity of the firm that operates each well in the dataset.
Latitude of Well	Coordinate that specifies north-south geographic position of a well.
Longitude of Well	Coordinate that specifies east-west geographic position of a well.
Market ID	Geographic region in which firms could share pipeline investment costs for a group of wells to some extent. Markets are defined using a K-means clustering algorithm.
Number of Wells of a Firm	Number of wells operated by the same firm in a given market.
Firms' Share of Wells	Share of wells operated by a firm in a given market.
Fraction Connected by Firm	Fraction of the total wells operated by a firm in a Market that are connected to the gas gathering network.
Number of Firms in Market	Number of firms operating in a market for natural gas gathering.
Number of Wells in Market	Number of wells in a market for natural gas gathering.
Market HHI (Wells)	Herfindahl-Hirschman index measure of concentration using the share of wells operated by a firm in a market.
Market Area	Area of a market in square miles.
Latitude of Processing Plant	Coordinate that specifies north-south geographic position of a processing plant.
Longitude of Processing Plant	Coordinate that specifies east-west geographic position of a processing plant.
Mkt Distance to Nearest PP	Distance from a market's midpoint to nearest processing plant.

Table A.1: Description of the Variables

Dependent Variable: Million Cubic Feet (MMCF) of Gas Flared

VARIABLES	(1) Model 1	(2) Model 2	(3) Model 3	(4) Model 4
Market HHI (Wells)	-373.3***	-405.9***	-284.0**	-314.6**
	(123.8)	(124.0)	(113.7)	(117.2)
Miles to Processing Plant (Hundreds)		-329.1***	-229.0*	-195.7*
		(106.9)	(114.0)	(113.4)
Number of Wells in Market (Thousands)			681.4***	709.0***
			(248.6)	(246.1)
Well Density (Thousand Wells per Sq. Mile)				6,895
				(5,124)
Constant	305.4***	364.3***	161.3*	129.1
	(59.98)	(67.42)	(88.18)	(86.43)
Observations	50	50	50	50
R-squared	0.081	0.145	0.280	0.302

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table A.2: OLS Regression of Volume of Natural Gas Output Flared (January 2015)

Dependent Variable: Fraction of Wells Connected

VARIABLES	(1) Model 1	(2) Model 2	(3) Model 3	(4) Model 4
HHI (Gas Vol. In MCF)	-0.0376	0.0647	0.153	0.126
	(0.217)	(0.101)	(0.114)	(0.109)
Miles to Processing Plant (Hundreds)		-1.320***	-1.235***	-1.211***
		(0.182)	(0.154)	(0.148)
Market-level Gas Output (BCF)			0.0811***	0.0713***
			(0.0247)	(0.0244)
Well Density				6.725**
				(2.940)
Constant	0.857***	1.015***	0.899***	0.884***
	(0.0861)	(0.0419)	(0.0649)	(0.0640)
Observations	50	50	50	50
R-squared	0.001	0.668	0.721	0.734

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table A.3: OLS Regression of Fraction of Wells Connected (January 2015)

A.3 Data Scraping

I obtain the main data for my analysis from the NDIC website. The entire monthly production history of every well permitted by the NDIC in the Bakken is available through the website's premium subscription services. The monthly production data are only available as HTML tables. Therefore, I write a Python program that navigates through each of the availabe tables [25] and saves it as a .csv file. Each of the tables contains the following variables: "File No", "API No", "Pool", "Date", "BBLS Oil", "BBLS Water", "MCF Gas", "Days Produced", "Oil Sold", "MCF Sold", and "MCF Flared". I append the monthly well-level production data into a single dataset.

Additionally, I download the complete index of all wells permitted in North Dakota. This in-

[25] There is a table available for each month of the year starting in July 1951 until the current month of the year.

dex is available as a Microsoft Excel file for download. This file does not contain production data but contains the following variables for each well: “APINo”, “FileNo”, “CurrentOperator”, “CurrentWellName”, “LeaseName”, “LeaseNumber”, “OriginalOperator”, “OriginalWellName”, “SpudDate”, “TD” (total depth), “CountyName”, “Township”, “Range”, “Section”, “QQ”, “Footages”, “FieldName”, “ProducedPools”, “OilWaterGasCums”, “IPTDateOilWaterGas”, “Wellbore” “Latitude”, “Longitude”, “WellType”, “WellStatus”, “CTB”, and “WellStatusDate”. I merge these columns into the monthly well-level production data using the file number.

The NDIC also provides detailed geographic data through its GIS Map Server. Moreover, it is possible to download the shape files that feed NDIC’s GIS tool. Because I need the geographic coordinates of the wells to define “markets” for my empirical analysis, I download the *Wells.shp* file. This file contains the “latitude” and “longitude” of each well in addition to other attributes of each well. The variables contained in this file are the same as those contained in the well index, except for the geographic location information. I merge the “latitude” and “longitude” variables to the production data using the file number.

Moreover, I also download the *GasPlants.shp* file from the GIS Map Server tool. This file contains the exact geographic location of each natural gas processing plant in North Dakota. It also contains additional information regarding each processing plant, such as “name”, “operator”, and “status”.

Finally, I use the maps published by the North Dakota Pipeline Authority to learn which processing plants were active in a given month in the past. For example, in February 2015, there were nineteen active processing plants in North Dakota: Badlands, Belfield, Dewitt, Garden Creek, Hay Butte, Knuston, Lignite, Little Knife, Marmarth, Mckenzie Grasslands, Nesson, Norse Gas Plant, Palermo, Red Wing Creek Gas Plant II, Robinson Lake, Stateline Plant, Targa Badlands, Tioga, and Watford City Gas Plant.

In February 2017 there were twenty-four active processing plants in North Dakota: 1804 Springbrook, Badlands, Bear Creek, Belfield, County Line, Dewitt, Garden Creek, Hay Butte, Knuston, Lignite, Little Knife, Marmarth, Mckenzie Grasslands, Nesson, Norse Gas Plant, Palermo, Ray Plant, Red Wing Creek Gas Plant II, Robinson Lake, Roosvelt, Stateline Plant, Targa Badlands, Tioga, and Watford City Gas Plant.

A.4 K-means Algorithm

- **Objective function**:

$$J = \sum_{n=1}^{N} \sum_{k=1}^{K} r_{nk} * d(x_i, \mu_k),$$

- **Goal**: Find values for the $\{r_{nk}\}$ and the $\{\mu_k\}$ so as to minimize J.
- Step 0: Choose the number K of clusters to generate.
- Step 1: Choose some initial values for the μ_k. Randomly select K points in the space representation of objects that will be clustered. These point represent initial cluster centers.
- Step 2: Generate K clusters: assign the n^{th} data point to the closest cluster center.
- Step 3: Given the new K clusters, recompute the new cluster centers.
- Step 4: Repeat Steps 2 and 3 until there is no change in each cluster centroid. This will produce the classification into K separate clusters.

A.5 Computation of the Derivative in the First Order Condition

Let $\underline{\epsilon}$ be the error term from the marginal well connected by firm j in market m. Because wells are drawn from the same distribution, $\underline{\epsilon}$ is a cut-off error term. In other words, all wells such that $\epsilon_{ijm} > \underline{\epsilon}$ are going to be connected. It follows that the fraction of wells connected by firm j in market m can be expressed as

$$f_{jm} = 1 - G_\epsilon(\underline{\epsilon}). \tag{27}$$

For well-level unobservables distributed logistic, it follows that

$$\underline{\epsilon} = G_\epsilon^{-1}(1 - f_{jm}) = \ln\Big(\frac{1 - f_{jm}}{f_{jm}}\Big). \tag{28}$$

Computation of the following derivative follows from a straightforward application of Leibniz's rule:

$$\frac{d}{df_{jm}}[\int_{G_\epsilon^{-1}(1-f_{jm})}^{\infty}\epsilon_{ijm}g_\epsilon(\epsilon_{ijm})d\epsilon_{ijm}]I_m = -G_\epsilon^{-1}(1-f_{jm})g_\epsilon(G_\epsilon^{-1}(1-f_{jm}))\frac{dG_\epsilon^{-1}(1-f_{jm})}{df_{jm}} \tag{29}$$
$$= -\ln\Big(\frac{f_{jm}}{1-f_{jm}}\Big)$$

A.6 Fixed Point Condition

$$\text{F.O.C.}[f_{1m}]: \quad \lambda r_m I_m + \frac{\partial}{\partial f_{1m}}[\int_{\bar{\epsilon}=G_\epsilon^{-1}(1-f_{1m})}^{\infty}\epsilon_{im}g_\epsilon(\epsilon_{im})d\epsilon_{im}]I_m - \frac{\partial \widetilde{TC}_m}{\partial f_{1m}} = 0 \tag{30}$$

Substituting equation (29) into the first-order condition yields:

$$\lambda r_m - \frac{1}{I_m}\times\frac{\partial \widetilde{TC}_m}{\partial f_{1m}} = \ln\Big(\frac{f_{jm}}{1-f_{jm}}\Big). \tag{31}$$

Use the exponential function on both sides:

$$f_{1m}^* = \frac{\exp(\lambda r_m - \widetilde{MC}_m(f_{1m}^*, I_m;\theta^c))}{1+\exp(\lambda r_m - \widetilde{MC}_m(f_{1m}^*, I_m;\theta^c))}. \tag{32}$$

Note that

$$\widetilde{MC}_m(f_{1m}^*, I_m;\theta^c)) = \frac{1}{I_m}\times\frac{\partial \widetilde{TC}_m}{\partial f_{1m}}. \tag{33}$$

A.7 Computation of the Integral for Welfare Analysis

$$\begin{aligned}\int_{G_\epsilon^{-1}(1-f_{jm}^{\alpha=1})}^{G_\epsilon^{-1}(1-f_{jm}^{\alpha=\hat{\alpha}})} x g_\epsilon(x)dx &= \int_{G_\epsilon^{-1}(1-f_{jm}^{\alpha=1})}^{G_\epsilon^{-1}(1-f_{jm}^{\alpha=\hat{\alpha}})}\Big[x\frac{e^{-x}}{(1+e^{-x})^2}\Big]dx \\ &= \int_{1-f_{jm}^{\alpha=1}}^{1-f_{jm}^{\alpha=\hat{\alpha}}} \ln(u)-\ln(1-u)du \\ &= (1-f_{jm}^{\alpha=\hat{\alpha}})\ln(1-f_{jm}^{\alpha=\hat{\alpha}}) - (1-f_{jm}^{\alpha=1})\ln(1-f_{jm}^{\alpha=1}) \\ &\quad + (f_{jm}^{\alpha=\hat{\alpha}})\ln(f_{jm}^{\alpha=\hat{\alpha}}) - (f_{jm}^{\alpha=1})\ln(f_{jm}^{\alpha=1})\end{aligned} \tag{34}$$

I will compute the integral by substitution. I start by defining u as follows:

$$u = G_\epsilon(x) = \frac{1}{1 + e^{-x}}. \tag{35}$$

Therefore

$$x = \ln(u) - \ln(1 - u) \tag{36}$$

and

$$du = \frac{e^{-x}}{(1 + e^{-x})^2} dx. \tag{37}$$

I substitute equations (35)-(37) into (34) to get the expression after the second equality.

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