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deep blue sea starts … with a trickle

Company Profile

LGX ENERGY CORP.

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Disclosure: Portions of this report are excerpted from LGX Energy's website(s), presentations or other public collateral. We have attempted to identify those excerpts by *italicizing* them in the text.

Company Overview

LGX Energy is an early-stage oil and gas company focused on the development of an existing property in what is referred to as the Thomas Field, located in Clay County Indiana. The property includes current production of approximately 400 barrels per month. That production roughly covers the overhead of the Company.

The property was acquired in January 2022 and included 300+ miles of 2D seismic data. Aside from the existing production and access to the acquired seismic, the Company believes the area, and by extension the project, has several characteristics that make it particularly attractive in the current environment. For instance, as we will expand upon below, Indiana has historically had periods of robust oil and gas production and they still produce both. As a result, they have entrenched oil fields service providers, as well as adequate gas gathering, storage and transport infrastructure. Moreover, many of the potentially productive zones are in rural/agrarian areas with established roads/access. In addition, the state is generally favorable to the industry and landowner royalties are inexpensive relative to many other productive basins around the

country. Further, productive geologic formations are generally shallow which also keeps drilling and completion costs relatively low.
The LGX team includes a handful of industry people who have spent their careers in oil and gas with a mix of disciplines including geology, seismic data interpretation, land acquisition, field operations and others. Moreover, they have also spent much of their careers in and/or around the Illinois Basin, and they are quite familiar with the basin and formations therein. Further, the team was also (originally) responsible for the aggregation and development (including the seismic) of LGX's acquisition. Their knowledge of and prior work on the property was the basis for their decision to acquire these particular asset(s) and to focus on the development of the area.

From a valuation perspective, the Company recently raised $1.5 million, of which about $265,000 was used to repay a bridge loan that financed the acquisition. The rest of the capital (approximately $1.3 million) remains in the bank, and will be used to interpret, complete and enhance existing seismic, and then to drill initial targets delineated by that seismic. As we understand it, the financing round was done at $.20 per share, and we believe the round remains open, but people will need to discuss that with the Company directly. There are approximately 15 million shares outstanding, which puts the valuation at roughly $3 million (enterprise value is closer to $1.7 million). That said, here is a brief example of the economics they are targeting.

To reiterate, they intend to (initially) drill relatively shallow wells targeting known producing formations. As a result, they anticipate relatively modest drilling costs, spending approximately $150,000 per hole, with completion costing another $125,000. Given those metrics, ***hypothetically***, if they drill 4 holes and one is successful (25%), they will spend $725,000. If the successful well achieves initial production of 60 bbls/day and declines 50% by the end of year one, the well will produce an average of roughly 50 bls/day over the first 12 months or about 18,000 bbls over the first 12 months. They believe their lifting costs will be around $15 (all in). Thus, if we assume $90 oil less $15 in costs, ($75) multiplied by 18,000 bbls, the net revenues are approximately $1.35 million. which implies a return of capital of around 6.6 months, and net cash flow of $600,000. Further, if they can find that one successful well, they believe they will have greater success drilling offset wells, which would in turn improve the individual economics of *these* wells considerably. The point is, with even modest success (25% in this example) and modest relative production rates, the math in Indiana can in fact work, largely because of the lower cost profile (primarily drilling shallow wells) of the project, which brings us to our next point.

Obviously, success here hinges on a handful of issues, including success rates, the accuracy of their cost estimates (can they drill and complete a hole for $275,000), the accuracy of their lifting costs, the production rates of successful wells, prevailing oil prices etc. Those are largely typical risks in many resource deals. The Company is prepared to defend why they believe they can achieve numbers in the realm of what we laid out above. From our perspective, that is precisely why we think the team's experience in the basin is a highly favorable aspect of the project. Moreover, it is also the reason we believe the acquisition of the seismic data is important as well. Here again we will let the Company carry that flag, but we think their view is that much of the success the basin as had in the past has largely been accomplished without the benefit of any measurable seismic assistance, and that would include improvements that have been made to the technology since it *may have* been used in the basin. From a high level, we think that is a portion of the thesis here. Further, while we noted, the valuation of the Company based on the current raise is approximately $3 million (enterprise value is $1.7 million). As we understand it, the Company believes it would cost somewhere in the realm of $3 million to duplicate the seismic they now have access to. In our view, that asset is topical to the current valuation, and frankly, given the risks associated with dry holes, we think the project would be markedly less attractive absent the data. That is just our view.

We would include one additional point with respect to the seismic data. The hypothetical here is that the Company's targets will be shallow zones that will produce like similar historic projects in the area. However, there have been discoveries with better production and there are multiple formations that could pay. That is, some of the historically lesser breached lower zones could hold substantially more resources. We think it is safe to say that, again with the benefit of more/better seismic data, that potential could be more open-ended than they are currently discussing.

In addition to the above, there are a handful of other key elements to the story that we think when considered in totality (not the least of which is higher energy prices), could collectively create an extraordinary opportunity. We will delineate those throughout the overview as well. Further, management's goal is to take the Company public which could provide shareholders with some liquidity visibility as well.

Industry and Technical Overview

To edify, we will discuss energy prices briefly in this section, and we will also discuss the industry as it pertains to Indiana specifically as well as some brief color on the associated geology.

It is difficult to discuss the current run-up in energy prices without delving into the political weeds of that phenomenon. That said, for the purpose of this document, we feel like it is required on some level to try to assess what the future may hold for energy prices and by extension energy producers (like LGX). Further, that discussion may also require delineation amongst oil producers in one part of the world versus another. For instance, we think it is reasonable to suggest that certainly some of the recent rise in energy prices is related to the policies of the current U.S. Administration that largely favor renewable energy sources and/or technologies, and by extension generally oppose policies that enhance or otherwise enable the production of domestic fossil fuels. Setting aside the political talking points, the notion that domestic policies aimed at reducing the output of the world's largest producer might lead to higher prices should not be hard to understand. That said, there are other dynamics that have also contributed to rising energy prices, and they have collectively created the perfect storm. The question is (as it always is) where do we go from here?

We think it is fair to say that historically, the "experts" have not generally posted a stellar recorded of predicting oil prices. To that point, here are two recent headlines regarding future oil prices from two of the world's larger banks:

- *Citing tighter market balances, Citi raised its second-quarter 2022 Brent price forecast by $14 to $113 per barrel, and the third and fourth quarter prices by $12, to $99 and $85, respectively. The bank estimates Brent to average* ***$75 per barrel in 2023, revised higher by $16****.*

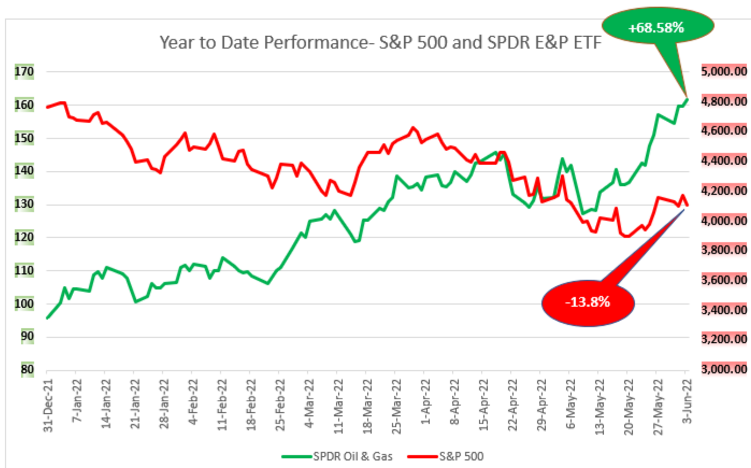
- *Goldman Sachs economists have predicted oil prices will surge to $140 a barrel this summer, with a drop in Russian production and a gradual recovery in Chinese demand adding to the pressure on already low supplies. But they said consumers will feel as though oil has hit $160 a barrel, because a lack of capacity at refineries means gasoline and fuel prices are rising more than would normally be expected, adding to costs across the economy. Goldman's analysts, including chief commodities strategist Jeff Currie, said in a note Monday that they expected prices to go higher "given the current record low levels of inventories."*

  …The investment bank said it expects prices to stay high, even though a surge to around $140 would trigger some "demand destruction" by encouraging people to stop using as much energy. Goldman said Brent oil prices would average ***$115 a barrel in the fourth quarter of 2023, with WTI averaging $110****.*

Obviously, these predictions are not on the same page, and we do not know which will be more correct, or for that matter if *either* will even be close. The point is, *nobody knows* where energy prices are headed, but what the past few months have taught us is that the higher they go, the more draconian their impact is on the world economy. From an investment perspective, what *we think* that means, is that wealth preservation going forward may require more attention to exposure to energy prices, which is a bit of the basis for this overview. In terms of the fundamentals, we think it is fair to say that fossil fuels are not getting easier to find, and they are getting more expensive to ship around the world (LNG for instance), which does not bode well for lower prices. Perhaps more importantly, the current climate change initiatives ostensibly being adopted by many of the world's industrialized nations does not bode well for ongoing investment in the fossil fuel space, which we think also tilts the bias towards lower future supply.

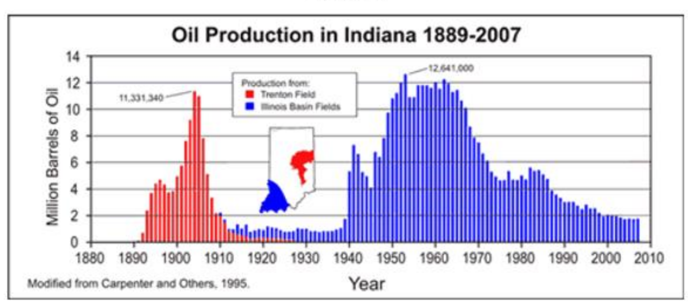
While we have certainly heard our share about the virtues of ESG and its contribution to risk management, investors may also need to start thinking about mitigating its costs. Perhaps Table 1. reflecting the YTD performance of the oil & gas sector versus the S&P 500 will help illustrate our point here:

Table 1.



Beyond the bigger macro stage (world energy prices), we think it is constructive for our "industry" overview to include some analysis of the energy industry in Indiana specifically, which will include some technical/geological observations as well. First as we alluded to above, Indiana has a rich history of both oil and gas production.

Table 2.



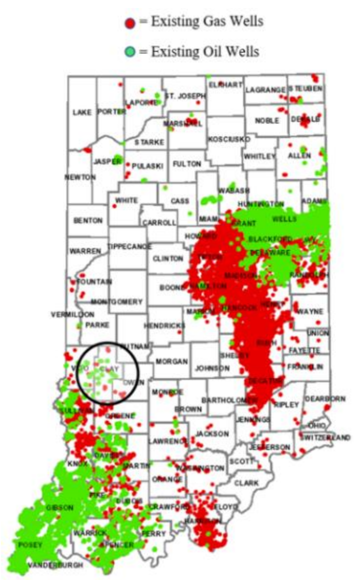
According to the Indiana Geology and Water Survey, "*America's first giant oil field was the Trenton Field of Indiana; gas was discovered there in 1876 in Delaware County. Beginning in 1886 and continuing into the first decade of the twentieth century, gas and then oil were discovered and developed in east-central Indiana. A wild unregulated boom ensued that ultimately resulted in thousands of wells being drilled. As gas and oil production declined in* *northern Indiana during the early 1900s, new discoveries were being made in the southwestern part of the state known as the Illinois Basin. Production reached a peak in 1956 at over 12 million barrels for the year and has declined gradually since then*". As LGX notes in its presentations, "*Indiana is part of the Illinois Geological Basin, which has produced over 4 billion barrels of oil and 4 trillion cubic feet of gas from over 85,000 historic oil and gas wells. Remaining reserves in the basin are estimated at 214 million barrels of oil and 4.65 trillion cubic feet of natural gas. Most historical oil development targeted shallow formations without the use of seismic data".*

To reiterate, the state has historically produced both oil and gas. As Table 2. reflects, much of the early development occurred in the east central portion of the state in the Trenton gas field. Incidentally, the production from the Trenton field was the genesis of John D. Rockefeller's Standard Oil Company. Recall, in 1911, via Sherman Antitrust actions, the federal government split Standard Oil into several pieces, which today include Chevron, ExxonMobil, Amoco, and Marathon Petroleum.

Within the Illinois Basin is a structure referred to as the Terre Haute Reef (sometimes referred to as the "Terre Haute Reef Bank"). The Terre Haute Reef is located in southwestern Indiana. Referring to Table 2. above, this portion of the state was largely responsible for Indiana's second energy boom (roughly 1940 through 1970+). Notice in Table 4. below, much of the production from this portion of the state has historically been oil production (represented by the **green dots**). The production the Company recently purchased is located in this area in what is referred to as the Thomas Field in Clay County, Indiana, which we circled in Table 4. Obviously, LGX is targeting production in this trend, so we will provide a bit more technical minutia in terms of the specific geology and associated formations, which should help readers better understand the Company's presentations that reference these formations. We realize this type of technical discussion is often hard to follow for non-geologists or other industry experts (we are neither), so we will try to keep this as brief yet informative as possible.

Table 3.

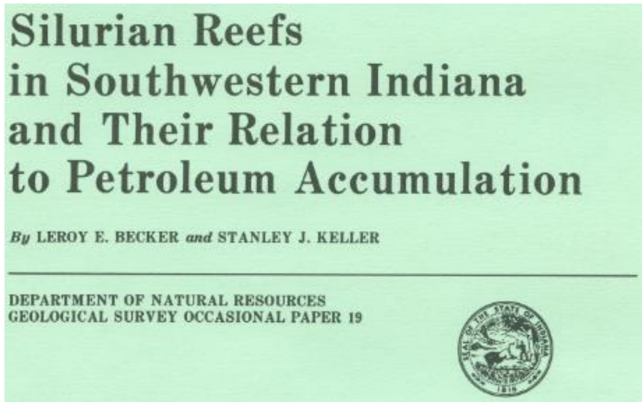
Table 4.



https://igws.indiana.edu/PDMS/Map/

To edify, some of the narrative below has been sourced from documents we were able to locate regarding the Illinois Basin the Terre Haute Reef and/or Silurian reefs, which are all topical to the area and the discussion herein. In that regard, we have labeled them 1 through 5, which we have in turn footnoted in the narrative below to identify each publication:

Publication (1)

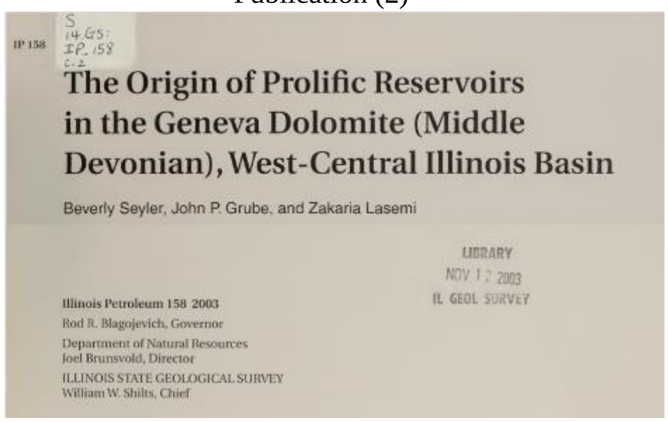


Silurian Reefs in Southwestern Indiana and Their Relation to Petroleum Accumulation

By LEROY E. BECKER and STANLEY J. KELLER

DEPARTMENT OF NATURAL RESOURCES
GEOLOGICAL SURVEY OCCASIONAL PAPER 19

Publication (2)

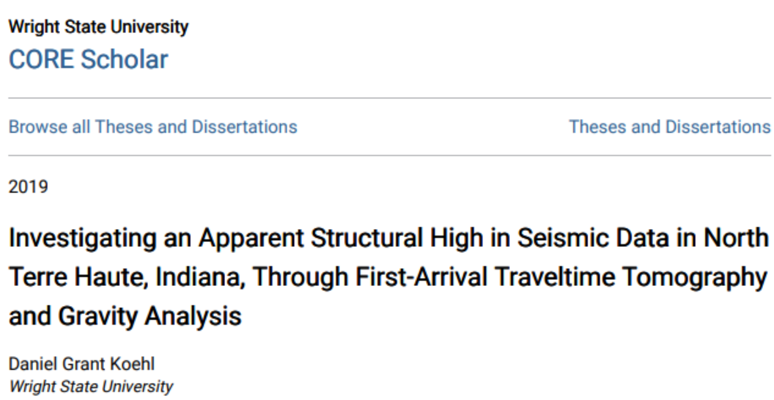


The Origin of Prolific Reservoirs in the Geneva Dolomite (Middle Devonian), West-Central Illinois Basin

Beverly Seyler, John P. Grube, and Zakaria Lasemi

Illinois Petroleum 158 2003
Rod R. Blagojevich, Governor
Department of Natural Resources
Joel Brunsvold, Director
ILLINOIS STATE GEOLOGICAL SURVEY
William W. Shilts, Chief

Publication (3)



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Investigating an Apparent Structural High in Seismic Data in North Terre Haute, Indiana, Through First-Arrival Traveltime Tomography and Gravity Analysis

Daniel Grant Koehl
Wright State University

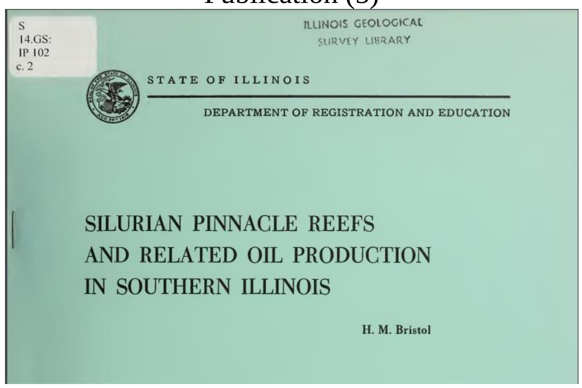
Publication (4)

Silurian Reef Systems in the Illinois and Michigan Basins - What can be Learned from Modern Quarrying Operations in North-Central Indiana*

Dennis R. Prezbindowski[1], Benjamin Dattilo[2], Jon Havens[3], and Rick Lucas[3]

Search and Discovery Article #51343 (2017)**
Posted April 24, 2018

Publication (5)

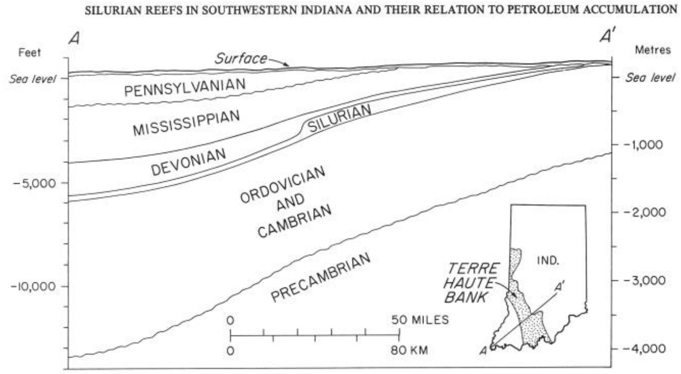


STATE OF ILLINOIS
DEPARTMENT OF REGISTRATION AND EDUCATION
SILURIAN PINNACLE REEFS
AND RELATED OIL PRODUCTION
IN SOUTHERN ILLINOIS
H. M. Bristol

To reiterate, we suspect it may be helpful for many if we first cover some of the geology vernacular used in these papers, as well as throughout some of the Company's presentations. Recognize, the broad stroke is that the Company intends to use its 2D seismic data to help identify potential targets that it can then in turn apply 3D seismic to, to identify the best targets to lease and then drill. That said, they are at least initially focused on trying to identify targets in some of the shallower formations within the Illinois Basin and more specifically, the Terre Haute Reef. First, Table 5. below {from **Publication (1)**} reflects the various formations found within the Illinois Basin and the Terre Haute Reef in southwestern Indiana. To edify, the Company often refers to one of their primary targets as the "Geneva Dolomite". As the narrative below notes, the Geneva Dolomite is part of the middle Devonian formation, and it has historically produced some prolific results:

Table 5.

SILURIAN REEFS IN SOUTHWESTERN INDIANA AND THEIR RELATION TO PETROLEUM ACCUMULATION



Cross section of Paleozoic rocks. "Devonian" includes that part of the Bailey Limestone that is probably Silurian in age.

The Geneva Dolomite, commonly the basal member of the Middle Devonian Grand Tower Limestone in much of the Illinois Basin, is an exploration target that has recently generated much interest.

Prolific reservoirs are associated with the Geneva Dolomite in the Illinois Basin. In March 2002, a new field discovery was completed immediately south of the Miletus Field in Marion County, Illinois, flowing oil at a rate of up to 3,000 barrels a day from a horizontal well bore. This prolific discovery in the Geneva Dolomite follows several earlier discoveries in the late 1990s that sparked the drilling of an assortment of exploratory wells in the region. The earlier wells were vertical tests and produced in excess of 300 barrels of oil per day. Production from these wells shows a low rate of decline. Three-dimensional (3-D) seismic technology was employed to establish the prospect. Further, the combined application of 3-D seismic and horizontal drilling technologies in the Illinois Basin should enhance the exploration and development opportunities in the Middle Devonian Geneva Dolomite as well as structural and stratigraphic prospects in other formations. These technologies have been implemented in other mature producing provinces but had not been proved and refined for application in the Illinois Basin until recently. **(Publication 2).**

We think there are two takeaways from the above narrative, first, recognize that, when we and/or the Company discuss the Geneva Dolomite, it generally coincides with the (middle) Devonian. Second, as the discussion reflects, some of the past success in the Geneva Dolomite was achieved via the use of seismic, which again is part of the thesis here. Granted, in the instance above, the success was in the Illinois Basin in Illinois (as opposed to Indiana), but the point is, there is an historical basis for the Company's focus on the formation.

In addition to LGX's focus on the Geneva Dolomite, they also suggest that they will be targeting "Silurian reefs" within the basin as well. Below is some narrative from **Publication (1)**, that we think is topical:

Reefs and reef structures are found across most of Indiana (Ault and others, in preparation), but reef structures commonly called pinnacle reefs have been recognized only in the Illinois Basin portion of Indiana. This report outlines briefly the distribution and stratigraphic setting of reef structures in the Illinois Basin of southwestern Indiana and the structural highs associated with them. It also includes comments on the occurrence of petroleum in the highs overlying the reefs and favorable areas of search for additional reefs.

Again, some assistance understanding the vernacular might be helpful. *Geological literature provides many different meanings for the term "reef". As commonly used by petroleum geologists, it means an irregular layered or mound-like carbonate rock body built by sedentary marine organisms, such as corals, and usually enclosed in rock of different lithology. Isolated reef growths that stand several hundred feet high and that generally cover less than 1 square mile are referred to as pinnacle reefs.*

Oil production from structural highs associated with Silurian reefs dates back to the discovery of the Terre Haute Field in Vigo County in 1889. The production at Terre Haute was derived from Devonian rocks, and at that time it was not known that the structural high that entrapped the oil was a reflection of an underlying Silurian reef. After the Terre Haute discovery, only three commercial pools related to reefs were discovered until the late 1040's and early 1950's when reef drilling exploration reached its peak. (By the way, this corresponds with the Table 2. above reflecting the peak of oil production in Indiana).

Table 6. {Pub. (1)}

SILURIAN REEFS IN SOUTHWESTERN INDIANA AND THEIR RELATION TO PETROLEUM ACCUMULATION

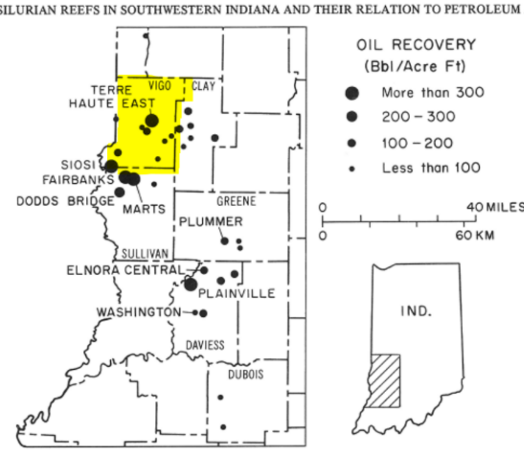


Figure 7. Oil recovery from fields associated with reef structures.

Tables 7 and 8 below from **Publication (1)**, are good illustrations of Silurian reefs in the Terre Haute Bank and some of the following narrative is supportive as well:

Table 7. {Publication (1)}

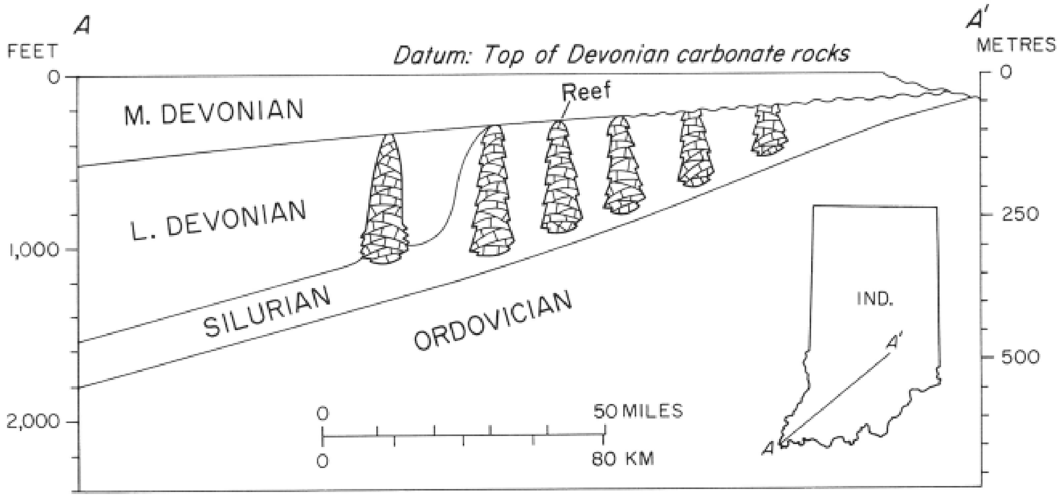


Figure 5. Cross section of Paleozoic rocks showing Silurian reefs. "Lower Devonian" includes that part of the Bailey Limestone that is probably Silurian in age.

Table 8. {Publication. (1)}

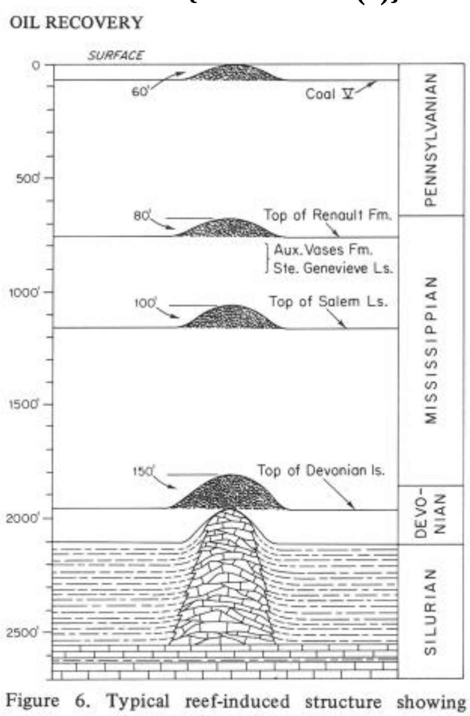


Figure 6. Typical reef-induced structure showing doming of strata above reef.

The doming of strata above a pinnacle reef resulted from differential compaction between the reef and the sediments adjacent to it. The reefs were rigid and thus permitted very little additional compaction from the weight of the overlying sentiments. By contrast the sediments around the reef were soft and were subjected *to considerable compaction. This differential compaction appears to have been continuous throughout post-Silurian time.*

Although structural closure or doming is apparent in all strata overlying a reef the amount of structural closure is greatest for the beds immediately above a reef. In the commercially significant reef belt of southwestern Indiana reef-induced structures of 150 feet on Devonian strata gradually diminishes upwards and is about 60 feet in the Pennsylvania Rocks of Coal V (Table 8.). In some areas including Michigan and Illinois petroleum is produced directly from the reef body in Indiana all commercial accumulation of petroleum found in association with Silurian reefs is rock overlying the reefs.

Oil or gas has been found in the domed beds above the reef in the Devonian limestone section the Salem limestone and the St. Genevieve of Aux Vases interval. Oil production has been obtained from reef related structures in 37 fields; from Devonian limestone in 20 fields from Mississippian reservoirs in 10 fields and from both Devonian and Mississippian rocks in seven fields.

There are indications that Silurian reef cores should be more thoroughly investigated even though no commercial production has been found within them in Indiana. At Shelburn Consolidated Field in Sullivan County the upper part of a Silurian reef was cord, and the core analysis indicated low oil saturation in a 2-foot interval. Shows of oil or gas have also been reported from the Howesville, Dixon and Switz city gas storage projects. At the Wilfred Field circulation was lost in the reef core during drilling thereby indicating porosity. ***Many of the Silurian pinnacle reefs are untested or inadequately tested.*** *Only nine of the 55 structure fields in west central Indiana have been drilled through the Silurian reef core. Of the remaining 46 reefs some 33 have some Silurian penetration and 13 have no penetration. In addition, any reefal complex found basinward from the thick Silurian section (Terra Haute Bank) will lie within the area where lower Devonian rocks are present. These lower Devonian rocks are generally less permeable than middle Devonian rocks and therefore may provide a seal that middle Devonian rocks thus far have not.*

Oil accumulations in Devonian limestone ***above Silurian reefs are significant****. Four fields Siosi, Fairbanks, Marts and Terre Haute East in Vigo and Sullivan counties compare favorably with any group of oil fields in Indiana. Ultimate recovery from them will be more than 11 million barrels an average of 2.75 million barrels per field. Oil recovery from these four fields will average more than 300 barrels per acre foot. The four fields are bounded by a group of Devonian reservoir fields based on Silurian reef structures. In one field Dodds bridge recovery has been between 200 and 300 barrels per acre foot and there are five fields in which recovery has been between 100 and 200 barrels per acre-foot. Other fields will yield less than 100 barrels per acre foot in Green and Owen Counties, southwest of the Devonian oilfields, gas has been found in the Devonian limestone above Silurian reefs. The gas accumulation in these fields were not sufficient in volume to be commercial but seven of the Green County fields have been developed for gas storage by Citizens Gas and Coke Utility. Reef induced structures in Greene, Davies and Dubois Counties hold important oil accumulations in Mississippian strata; Salem and St. Genevieve limestones and Aux Vases dolomite. Most reef related Mississippian reservoirs found in these counties prior to the Plumber discovery are commercial but Plainville with oil reserves reservoirs at depths of 700 to 750 feet has a recovery factor greater than 300 barrels per acre foot and is much better than the others. Ultimate recovery from it will be as much as 3.7 million barrels.*

The reef structure at Plummer was discovered in 1969 by shallow stratigraphic test drilling. Plumber turned out to hold a very significant oil accumulation in the Salem limestone (Mississippian) at a depth of 750 feet. In addition to the Salem production some production has been obtained from 20 Devonian wells. Ultimate recovery from Plumber maybe as much as 4.0 million barrels.

To unpack some of the above, the narrative is focused on fields in Indiana that have produced measurable amounts of oil (as well as gas in the cases of Marts and Siosi). **Table 9.** is a summary of some of those fields, and the green highlighted boxes represent those fields that were addressed specially by the narrative. To draw an important distinction here, these wells produced from the structures around the reef (Geneva Dolomite/Middle Devonian for instance, but not exclusively). Conversely, these wells did not produce from reservoirs within the reefs themselves. We will address that prospect further below, but to reiterate, the Company will attempt to identify targets among the reef caps (again the Geneva Dolomite for instance) but also potential reservoir targets *within the reef cores*, which as we will delineate, has proven successful in other portions of the Illinois and Michigan basins. We would add, notice that much of the narrative above also addresses another leg of the Company's thesis, which is that historically, the region has been successful exploiting resources at reasonably shallow depths (i.e. cheaper and easier to get to), although, we would submit that deeper formations may someday provide additional resource opportunities as well.

Table 9.

SILURIAN REEFS IN SOUTHWESTERN INDIANA AND THEIR RELATION TO PETROLEUM ACCUMULATION

Table 1. Oil, gas, and gas storage fields associated with reef-induced structures

Field name	County	Field usage[1]	Productive system[1]	Cumulative oil production (bbl) to Dec. 31, 1975
Arney	Owen	G	D	————
Art	Clay	O	M, D	48,816
Blackhawk	Vigo	O	D	533,980
Bowling Green	Clay	O	D	62,821
Bowling Green South	Clay	O	D	————
Carbon	Clay	GS	—	————
Coal City	Owen	G	D	————
Cory Consol.	Clay	O	D	109,850
Cory South	Clay	O	D	5,821
Covington	Fountain	G	P	————
Dixon	Greene	GS	—	————
Dodds Bridge	Sullivan	G, O	P, M, D	2,082,063
Elnora Central	Daviess	O	M	747,728
Fairbanks	Sullivan	O	D	2,930,109
Glendale	Daviess	G	D	————
Green Hill	Warren	GS	—	————
Howesville	Greene	GS, G	D	————
Huntingburg	Dubois	G, O	P, M	563,986
Ireland	Dubois	G, O	M	2,561
Iva East	Pike	G, O	M	————
Lewis	Sullivan	O	D	————
Linton	Greene	GS, G	D	————
Lonetree	Greene	GS, G	D	————
Lyons	Greene	G, O	D	————
Lyons West	Greene	G	D	————
Marts	Sullivan	G, O	P, D	2,440,127
Mineral City	Greene	GS, O	M	9,376
Montezuma	Vermillion	GS, O	D	11,663
Montezuma South	Vermillion	GS	—	————
Montgomery	Daviess	O	M	664,750
Odon East	Daviess	G, O	M, D	448,593
Odon North	Daviess	G	D	————
Odon South	Daviess	O	M	4,034
Plainville	Daviess	G, O	M, D	3,524,870
Plummer	Greene	G, O	M, D	2,705,772
Portersville West	Daviess	G	D	————
Prairie Creek	Vigo	G, O	P, M, D	1,869,299
Riley	Vigo	O	D	11,029
Riley South	Vigo	O	M, D	772,032
Saline City	Clay	O	D	30,296
Sandborn North	Greene	G	D	————
Shelburn Consol.	Sullivan	G, O	P, D	37,236
Simpson Chapel	Greene	GS, O	M	7,626
Siosi	Vigo and Sullivan	G, O	P, D	4,637,288
Spring Hill	Vigo	O	D	963,752
State Line	Vigo	GS, O	D	19,251
Staunton	Clay	O	D	247,571
Switz City	Greene	GS, G	D	————
Terre Haute	Vigo	O	D	————
Terre Haute East	Vigo	O	D	1,704,432
Terre Haute South	Vigo	O	M, D	345,112
Washington	Daviess	O	M	283,270
Westpoint	Tippecanoe	GS	—	————
Wilfred	Sullivan	GS, G, O	D	203,652
Worthington	Greene	GS	—	————
				28,028,766

[1]Abbreviations: G - Gas; O - Oil; GS - Gas storage; P - Pennsylvanian rocks; M - Mississippian rocks; D - Devonian rocks.

To extend our line of thinking here, the narrative below is from **Publication 4**, which addresses Silurian reef reservoirs, in other parts of the Illinois and Michigan basins.

The quarrying of dolomite and limestone material from the Silurian of North Central Indiana has been ongoing for over 100 years. These quarrying operations are located near the crest of the northwest to southeast trending Cincinnati Arch, generally along river valleys where the amount of glacial overburden that needs to be removed prior to quarrying is minimal. These quarrying operations have created vertical outcrops that can be hundreds of feet in height and over a thousand feet length of Silurian carbonates. A significant number of these quarrying operations have cross-cut and exposed Silurian Reef complexes. These reef complexes range from 10's of feet to over 1000's feet in width and up to 100 feet in height.

Silurian reef complexes are very important oil and gas reservoirs in the Michigan and Illinois basins. In the Michigan Basin, over a thousand reef complex oil and gas fields have been discovered since 1950's producing over 450 MMBO to date. While in the Illinois Basin, production from Silurian reef complexes was initiated in 1946 with over 130 MMBO having been produced to date from over 26 reef complex reservoirs. Unfortunately, many of the Silurian reef reservoirs discovered in the 1950's through the 1980's are poorly documented by seismic, incomplete well penetrations of the reservoir interval, limited well logs and core material. The majority of wells did not penetrate through the complex reservoir zone. As a result, very limited core material is available, some of which is fragmented and poorly marked (limited core analyses data) and old electric logs that only record the contact of the reef reservoir with the overlying seal facies are common. Further, very limited production data is available from these reservoirs. Future enhanced, oil and gas *recovery and exploration programs targeting Silurian Reef reservoirs will depend on a better understanding of these complex carbonate reservoir systems to be successful.*

To summarize, there are a few salient points regarding the Company's approach (the "thesis" as we have termed it) in Indiana. First, while Indiana is probably not the first area that comes to mind when discussing the most prolific domestic oil and gas regions, the fact is, *it is* one of the nation's *first* prolific oil and gas regions and as such it has a proven record of production success. To that point, we would argue that the region's *early success* may have played a role in it subsequently taking a back seat to other prolific oil and gas basins/regions around the U.S. We know for instance that unlike some of the others, the Illinois Basin's resources were relatively shallow, which on the face made them more amenable to discovery and production than perhaps other regions that subsequently flourished with the benefits of advanced technologies and techniques. That brings us to our next point.

We referenced **Publication 3** above, which is largely a technical paper addressing the use and interpretation of seismic data in Indiana. It notes the following. "*Misinterpreted geologic structures are a daily occurrence within the exploration industry. More care should be put into quality processing rather than "all purpose" processing flows and basic geologic considerations. Every study site has a different geologic history, and it should be treated as such. Inclusion of several geophysical techniques are necessary for a proper interpretation of the complex features within a study area".* We think this speaks to another of the legs to the thesis here, which is that while Indiana has produced a fair amount of oil and gas, much of it has been discovered without the use of sophisticated technology like seismic, and as such it leaves the door open to the possibility that applying these advances to additional portions of the region could provide significant benefit in terms of locating and developing additional resources. That said, we would argue that applying some of these technologies is not inexpensive and those capital outlays need to be weighed against the potential for success and its magnitude therein. From a practical standpoint, the historic well economics in Indiana have not been as attractive as those in other more prolific regions, so on the face it is easy to understand how capital flowed to those more prolific regions and in turn some of those technologies were never applied there in earnest. To put that into perspective, we would suggest that without the benefit of the seismic data LGX was able to acquire in conjunction with the production in Clay County, *we do not think* the Company would be looking to further develop this portion of the country. Of course, that statement may be less valid as oil prices continue to rise, but even at $120 oil, we believe they would have to think long and hard about spending $3 million up front on seismic data.

Lastly, while they may not have been inclined to go down this road without the seismic data, they do not have to because *they already have* the seismic data. With that in hand, as we have attempted to describe above, we think they can use that data (in conjunction with other technology they will bring to bear), to identify potential targets in formations (Geneva Dolomite, Silurian reefs and others) that have been proven producers in the past. As we will demonstrate in the Operating and Valuation sections below, we think the Company can achieve marked financial success even with moderate exploration and development success.

Project and Operating Overview

LGX is an early-stage venture and as such it has limited historic operating information that might otherwise allow us to establish a baseline from which to develop a future operating model. Management indicates that the current operating overhead is around $35,000 per month, which we believe is being largely covered by the production from the acquired in the Thomas Field. Given that limited information, we have nonetheless attempted to build an operating model around what we have seen in the past in terms of similar operations.

In that regard, as we understand it, much of the operating team we described prior, as well as via the included biographies, is being compensated largely on a revenue share percentage, that involves some caps and incentives. We have worked those metrics into our model assumptions as we understand them, but recognize, those incentives are perhaps in leu of what might otherwise be larger operating overhead than we might see in typical enterprises. To translate, while it is early and operating levels could certainly prove to be higher than we are anticipating, we think our assessments herein are reasonable in the context of how we understand the business and its anticipated operations. In addition, per company guidance, we have assumed all-in lifting costs of $15 per barrel. That could provide aggressive or otherwise as they move to actual production.

As we also referenced above, the Company raised initial capital through a "friends and family" round priced at $.20 per share, which we think they will be closing imminently. As a result of that raise, they currently have cash on hand of approximately $1.4 million, which they will be using to support additional seismic studies and to drill initial wells.

Management anticipates drilling relatively shallow wells, which they believe will result in initial well costs of $150,000. Further, they believe they can complete successful wells for and addition $125,000. Our model assumes that they will drill wells as existing and assumed future internally generated cash will allow. That is, we have not modeled additional capital raises or other arrangements to support exploration and development endeavors. Obviously, additional capital, which could dilutive, could accelerate exploration and potential operating well profiles. As an extension, in the Valuation and Sensitivity Analysis below, we have provided some iterations regarding drilling success, oil prices etc. to illustrate the relationships/sensitivity to some of the more topical variables. As we think those matrices will help demonstrate, there is considerable volatility in the potential outcomes given different assumptions/mixes of those inputs.

In addition to the breadth of these more topical variables, we submit that *the timing* of these variables could also be subject to considerable volatility. While we have attempted to smooth our modeling with respect to some of these issues, their actual timing could significantly alter the accuracy of our model assessments. For instance, if we assume they will need to drill 3 dry wells to find 1 productive well, the sequence of those wells could be impactful. That is, hitting the successful well on attempt number 1, will likely be more advantageous than hitting the successful well on attempt number 4. That is especially true given our approach of assuming that future exploration and development will be funded via organic means, because presumably hitting a successful well sooner, would provide more near terms cash flow to drill more/subsequent wells. Clearly, the timing of actual events could negatively impact our model assumptions, although we would also submit that we suspect the Company will pursue additional development capital in one form or another to augment internally generated cash to support/accelerate further exploration and development. To edify, that could mean more equity raises or it could mean the establishment of non-dilutive drilling programs (for instance). Regardless, we have not modeled those iterations.

To reiterate, the nascent nature of the enterprise lends itself to poor visibility with respect to both exploration/development and ultimately anticipated production. That visibility includes the variables we will cover in the Valuation and Sensitivity Analysis below, such as prevailing oil prices, their success identifying productive wells, the rates at which those successful wells will produce and others. On the flip side of that coin, we think the Company's access to the considerable cache of proprietary seismic data we alluded to above should improve the visibility of the exploration and development success, which in turn should shed better light on their financial performance. Again, that access and its implications are a considerable portion of the constructive thesis.

Valuation and Sensitivity Analysis

As we noted, the Company is in the process of completing its "friends and family" round of financing, which entails the sale of common shares at $.20 per share. We estimate that following the completion of that raise, the Company should have approximately 18 million shares outstanding, for a post money valuation of around $3.6 million, and an enterprise value of approximately $2 million. From that starting point, we have developed a set of matrices to help frame the potential valuation of the Company as we see it. Recognize, there are several variables that will help determine that valuation and/or the Company's success. Those variables include oil prices, their success in developing producing wells and the degree(s) to which those wells produce. Clearly, there are other variables that will impact their outcome(s), but these are some of the major components we are focused on.

To edify, we have provided three different scenarios and each scenario includes two iterations. Each scenario starts with a set of assumptions about the Company's assumed exploration and development success and those assumptions are denoted at the top of each matrix. From example, in Scenario 1, Iteration 1 we assume the Company will achieve 30% initial success in discovering initial wells. We also assume that thereafter, they will achieve 80% success drilling additional wells in that same field and each field will include a total of 9 wells. Further, each scenario includes two additional variables, each on a separate axis: varying assumed oil prices on the horizontal (x) axis, and varying initial flow rates of each well on the vertical (y) axis. Additionally, in each iteration of each scenario, we have accented the 30 barrels per day initial flow rate row(s), as this is the flow rate the Company has used as their base case hypotheticals.

In addition, each scenario has two iterations. Iteration 1 represents our estimated matrix of valuations of the Company given the different mixes of the variables we noted above and using a projected discounted cash flow (DCF) method to arrive at a net present value (NPV) given a discount rate (their theoretical cost of capital) of 10%. By the way that discount rate ("PV10") is a typical metric in the resource space. On the other hand, *Iteration 2* reflects the same set of inputs, but it assumes a discount rate of 20% ("PV20"). In theory, higher discount rates equate to higher costs of capital and the inference is that investors in early-stage companies (with poor visibility) require higher returns (i.e. higher "costs of capital") to compensate for that added risk and/or lack of visibility. Put another way, in our public company research, we use additional discount rates to arrive at our valuations/price targets as a means of "handicapping" the notion that our projected cash flow models will prove more aggressive than the reality. In any event, Iteration 2 of each scenario reflects the more deeply discounted valuation assessment, and in our view, is probably the most appropriate approach given the current early-stage posture of the enterprise.

Lastly, notice there is considerable variability in the results across these scenarios, which illustrates the sensitivity of the model to these inputs/variables. Further, keep in mind that the current funding round is being completed at $.20, so any result above $.20 would reflect a premium to the valuation implied by that financing.

The above noted, the following pages include the scenarios/iterations we addressed above as well as a bit of color regarding each.

Scenario 1.

This scenario represents the examples the Company provides in its presentations, which includes an initial well success rate of 30%, an additional field well success rate of 80%, and an assumption that each field will support 9 producing wells. These numbers are quite robust.

SCENARIO 1, ITERATION 1

Assume 30% Initial Well Success
Assume 80% Field Well Success
Assume 9 Wells per Field
Hypothetical Per Share NPV Values @10% Discount "PV10"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10									$ 0.26	$ 0.77	$ 1.05	$ 2.09
15					$ 0.05	$ 0.42	$ 0.81	$ 1.18	$ 2.00	$ 2.89	$ 3.68	$ 5.10
20			$ 0.11	$ 0.59	$ 1.11	$ 1.67	$ 2.18	$ 2.81	$ 3.87	$ 5.15	$ 6.25	$ 8.26
25		$ 0.28	$ 0.92	$ 1.60	$ 2.24	$ 3.00	$ 3.66	$ 4.52	$ 5.90	$ 7.60	$ 9.04	$ 11.70
30	$ 0.22	$ 0.98	$ 1.79	$ 2.55	$ 3.46	$ 4.25	* $5.27	$ 6.10	$ 8.10	$ 10.26	$ 12.06	$ 15.41
35	$ 0.77	$ 1.73	$ 2.62	$ 3.66	$ 4.79	$ 5.76	$ 6.72	$ 8.02	$ 10.48	$ 12.58	$ 15.33	$ 18.61
40	$ 1.36	$ 2.43	$ 3.60	$ 4.86	$ 5.96	$ 7.06	$ 8.53	$ 9.68	$ 12.50	$ 15.56	$ 18.06	$ 21.81
45	$ 1.99	$ 3.27	$ 4.46	$ 5.90	$ 7.13	$ 8.75	$ 10.04	$ 11.83	$ 14.42	$ 17.10	$ 19.78	$ 29.90
50	$ 2.57	$ 4.00	$ 5.24	$ 6.85	$ 8.21	$ 10.02	$ 11.44	$ 12.86	$ 16.43	$ 19.41	$ 22.38	$ 28.08
55	$ 3.08	$ 4.66	$ 6.38	$ 7.87	$ 9.81	$ 11.37	$ 12.93	$ 15.17	$ 10.44	$ 21.71	$ 26.14	$ 31.27
60	$ 3.82	$ 5.38	$ 7.27	$ 8.89	$ 11.02	$ 12.72	$ 15.10	$ 16.88	$ 20.45	$ 25.13	$ 28.86	** $34.45

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV10** valuation is $5.27. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $19.3 million and eps of $.26, for a P/E mutiple of 20.3X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV10 valuation is $34.45. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $57.7 million and eps of $1.32, for a P/E mutiple of 26X

SCENARIO 1, ITERATION 2

Assume 30% Initial Well Success
Assume 80% Field Well Success
Assume 9 Wells per Field
Hypothetical Per Share NPV Values @20% Discount "PV20"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10									$ 0.13	$ 0.38	$ 0.64	$ 2.09
15					$ 0.03	$ 0.21	$ 0.39	$ 0.57	$ 0.97	$ 1.40	$ 1.79	$ 2.48
20			$ 0.06	$ 0.29	$ 0.53	$ 0.81	$ 1.05	$ 1.36	$ 1.87	$ 2.50	$ 3.04	$ 4.03
25		$ 0.14	$ 0.44	$ 0.77	$ 1.08	$ 1.45	$ 1.77	$ 2.19	$ 2.86	$ 3.71	$ 4.41	$ 5.74
30	$ 0.11	$ 0.47	$ 0.86	$ 1.23	$ 1.67	$ 2.06	* $2.56	$ 2.96	$ 3.95	$ 5.03	$ 5.91	$ 7.61
35	$ 0.37	$ 0.83	$ 1.26	$ 1.77	$ 2.32	$ 2.79	$ 3.26	$ 3.91	$ 5.14	$ 6.17	$ 7.57	$ 9.19
40	$ 0.65	$ 1.17	$ 1.74	$ 2.36	$ 2.89	$ 3.42	$ 4.15	$ 4.71	$ 6.16	$ 7.68	$ 8.91	$ 10.77
45	$ 0.96	$ 1.58	$ 2.15	$ 2.86	$ 3.46	$ 4.26	$ 4.89	$ 5.80	$ 7.03	$ 8.33	$ 9.64	$ 12.24
50	$ 1.23	$ 1.93	$ 2.50	$ 3.28	$ 3.94	$ 4.84	$ 5.53	$ 6.21	$ 8.01	$ 9.45	$ 10.90	$ 13.80
55	$ 1.46	$ 2.22	$ 3.06	$ 3.77	$ 4.74	$ 5.49	$ 6.25	$ 7.39	$ 8.98	$ 10.58	$ 12.84	$ 15.37
60	$ 1.82	$ 2.56	$ 3.48	$ 4.26	$ 5.32	$ 6.15	$ 7.36	$ 8.22	$ 9.96	$ 12.35	$ 14.18	** $16.93

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV20** valuation is $2.56. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $19.3 million and eps of $.26, for a P/E mutiple of 9.9X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV20 valuation is $16.93. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $57.7 million and eps of $1.32, for a P/E mutiple of 12.8X

Scenario 2.

This scenario includes an initial well success rate of 25%, an additional field well success rate of 33%, and an assumption that each field will support 5 producing wells. It is less aggressive than Scenario 1.

SCENARIO 2, ITERATION 1

Assume 25% Initial Well Success
Assume 33% Field Well Success
Assume 5 Wells per Field
Hypothetical Per Share NPV Values @10% Discount "PV10"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10										$ 0.02	$ 0.11	$ 0.27
15								$ 0.05	$ 0.20	$ 0.38	$ 0.56	$ 0.95
20					$ 0.02	$ 0.10	$ 0.21	$ 0.33	$ 0.58	$ 0.94	$ 1.22	$ 1.65
25				$ 0.08	$ 0.20	$ 0.35	$ 0.50	$ 0.69	$ 1.08	$ 1.42	$ 1.79	$ 2.25
30			$ 0.11	$ 0.26	$ 0.42	$ 0.63	* $.90	$ 1.11	$ 1.51	$ 1.95	$ 2.31	$ 3.14
35		$ 0.09	$ 0.27	$ 0.47	$ 0.75	$ 1.03	$ 1.23	$ 1.49	$ 1.98	$ 2.40	$ 2.95	$ 3.96
40	$ 0.02	$ 0.21	$ 0.43	$ 0.76	$ 1.07	$ 1.29	$ 1.58	$ 1.81	$ 2.38	$ 2.99	$ 3.65	$ 4.85
45	$ 0.13	$ 0.37	$ 0.64	$ 1.05	$ 1.30	$ 1.62	$ 1.97	$ 2.24	$ 2.90	$ 3.62	$ 4.40	$ 5.57
50	$ 0.24	$ 0.53	$ 0.93	$ 1.26	$ 1.60	$ 1.98	$ 2.28	$ 2.58	$ 3.47	$ 4.31	$ 5.23	$ 6.56
55	$ 0.35	$ 0.73	$ 1.16	$ 1.53	$ 1.85	$ 2.26	$ 2.59	$ 3.05	$ 3.91	$ 4.83	$ 5.84	$ 7.31
60	$ 0.48	$ 0.96	$ 1.34	$ 1.74	$ 2.18	$ 2.54	$ 3.03	$ 3.56	$ 4.54	$ 5.35	$ 6.46	** $8.07

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV10** valuation is $.90. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $4.7 million and eps of $.05, for a P/E mutiple of 18X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV10 valuation is $8.07. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $17 million and eps of $.37, for a P/E mutiple of 21.8X

SCENARIO 2, ITERATION 2

Assume 25% Initial Well Success
Assume 33% Field Well Success
Assume 5 wells per Field
Hypothetical Per Share NPV Values @20% Discount "PV20"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10										$ 0.01	$ 0.06	$ 0.14
15								$ 0.03	$ 0.10	$ 0.19	$ 0.28	$ 0.46
20					$ 0.01	$ 0.06	$ 0.11	$ 0.16	$ 0.29	$ 0.45	$ 0.59	$ 0.81
25				$ 0.04	$ 0.10	$ 0.17	$ 0.25	$ 0.34	$ 0.52	$ 0.69	$ 0.88	$ 1.10
30			$ 0.06	$ 0.13	$ 0.21	$ 0.31	* $.43	$ 0.53	$ 0.73	$ 0.95	$ 1.13	$ 1.56
35		$ 0.05	$ 0.13	$ 0.23	$ 0.36	$ 0.50	$ 0.59	$ 0.72	$ 0.97	$ 1.17	$ 1.45	$ 1.98
40	$ 0.02	$ 0.11	$ 0.21	$ 0.37	$ 0.51	$ 0.62	$ 0.77	$ 0.88	$ 1.16	$ 1.47	$ 1.80	$ 2.44
45	$ 0.07	$ 0.18	$ 0.31	$ 0.50	$ 0.63	$ 0.78	$ 0.96	$ 1.09	$ 1.42	$ 1.79	$ 2.19	$ 2.81
50	$ 0.12	$ 0.26	$ 0.45	$ 0.60	$ 0.78	$ 0.96	$ 1.11	$ 1.26	$ 1.71	$ 2.15	$ 2.63	$ 3.33
55	$ 0.17	$ 0.35	$ 0.56	$ 0.74	$ 0.89	$ 1.10	$ 1.26	$ 1.50	$ 1.93	$ 2.40	$ 2.94	$ 3.71
60	$ 0.23	$ 0.46	$ 0.64	$ 0.84	$ 1.06	$ 1.24	$ 1.49	$ 1.76	$ 2.26	$ 2.66	$ 3.25	** $4.09

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV20** valuation is $.43. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $4.7 million and eps of $.05, for a P/E mutiple of 8.6X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV20 valuation is $4.09. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $17 million and eps of $.37, for a P/E mutiple of 11X

Scenario 3.

This scenario includes an initial well success rate of 17% (1 in 6), an additional field well success rate of 33% (1 in 3), and an assumption that each field will support 5 producing wells. It is the least aggressive scenario of the three.

SCENARIO 3, ITERATION 1

Assume 17% Initial Well Success (1 in 6)
Assume 25% Field Well Success
Assume 5 Wells per Field
Hypothetical Per Share NPV Values @10% Discount "PV10"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10											$ 0.05	$ 0.15
15								$ -	$ 0.07	$ 0.20	$ 0.34	$ 0.57
20						$ 0.03	$ 0.07	$ 0.15	$ 0.32	$ 0.51	$ 0.73	$ 1.12
25				$ 0.01	$ 0.07	$ 0.16	$ 0.26	$ 0.38	$ 0.61	$ 1.00	$ 1.27	$ 1.61
30			$ 0.02	$ 0.08	$ 0.21	$ 0.34	* $.48	$ 0.62	$ 1.06	$ 1.38	$ 1.65	$ 2.14
35		$ 0.01	$ 0.08	$ 0.22	$ 0.37	$ 0.55	$ 0.73	$ 1.00	$ 1.40	$ 1.71	$ 2.11	$ 2.85
40		$ 0.06	$ 0.21	$ 0.38	$ 0.59	$ 0.82	$ 1.11	$ 1.28	$ 1.69	$ 2.13	$ 2.50	$ 3.49
45	$ 0.02	$ 0.15	$ 0.35	$ 0.55	$ 0.82	$ 1.14	$ 1.33	$ 1.59	$ 2.07	$ 2.48	$ 3.15	$ 4.01
50	$ 0.07	$ 0.26	$ 0.48	$ 0.73	$ 1.12	$ 1.33	$ 1.61	$ 1.83	$ 2.37	$ 2.95	$ 3.58	$ 4.72
55	$ 0.13	$ 0.38	$ 0.64	$ 1.02	$ 1.30	$ 1.60	$ 1.84	$ 2.17	$ 2.67	$ 3.46	$ 4.18	$ 5.27
60	$ 0.23	$ 0.49	$ 0.84	$ 1.22	$ 1.54	$ 1.80	$ 2.16	$ 2.43	$ 3.10	$ 3.83	$ 4.84	** $5.81

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV10** valuation is $.48. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $3.6 million and eps of $.04, for a P/E mutiple of 12X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV10 valuation is $8.07. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $12.7 million and eps of $.27, for a P/E mutiple of 21.5X

SCENARIO 3, ITERATION 2

Assume 17% Initial Well Success (1 in 6)
Assume 25% Field Well Success
Assume 5 Wells per Field
Hypothetical Per Share NPV Values @20% Discount "PV20"

Oil Prices → / Initial Flow (Bpd) ↓	$ 40	$ 45	$ 50	$ 55	$ 60	$ 65	$ 70	$ 75	$ 85	$ 95	$ 105	$ 120
10											$ 0.03	$ 0.08
15								$ -	$ 0.05	$ 0.11	$ 0.17	$ 0.28
20						$ 0.02	$ 0.04	$ 0.08	$ 0.16	$ 0.25	$ 0.36	$ 0.54
25				$ 0.01	$ 0.04	$ 0.08	$ 0.13	$ 0.19	$ 0.30	$ 0.48	$ 0.62	$ 0.78
30			$ 0.01	$ 0.05	$ 0.11	$ 0.17	* $.24	$ 0.31	$ 0.51	$ 0.67	$ 0.80	$ 1.04
35		$ 0.01	$ 0.05	$ 0.11	$ 0.19	$ 0.27	$ 0.36	$ 0.48	$ 0.68	$ 0.83	$ 1.03	$ 1.41
40		$ 0.04	$ 0.11	$ 0.19	$ 0.29	$ 0.40	$ 0.53	$ 0.62	$ 0.82	$ 1.04	$ 1.22	$ 1.74
45	$ 0.02	$ 0.08	$ 0.17	$ 0.27	$ 0.40	$ 0.55	$ 0.64	$ 0.77	$ 1.01	$ 1.21	$ 1.56	$ 2.00
50	$ 0.04	$ 0.13	$ 0.24	$ 0.36	$ 0.54	$ 0.64	$ 0.78	$ 0.88	$ 1.15	$ 1.44	$ 1.76	$ 2.37
55	$ 0.25	$ 0.19	$ 0.31	$ 0.49	$ 0.62	$ 0.77	$ 0.89	$ 1.05	$ 1.30	$ 1.71	$ 2.08	$ 2.64
60	$ 0.12	$ 0.24	$ 0.41	$ 0.58	$ 0.74	$ 0.87	$ 1.05	$ 1.18	$ 1.52	$ 1.89	$ 2.43	** $2.92

*Per our model assessments, at $70 oil and initial flow rates of 30 barrels/day, our estimated **NPV/PV20** valuation is $.24. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $3.6 million and eps of $.04, for a P/E mutiple of 6X

Per our model assessments, at $120 oil and initial flow rates of 60 barrels/day, our estimated **NPV/PV10 valuation is $8.07. For perspective, our model assumptions that derive that number correspond to 2024 revenues of $12.7 million and eps of $.27, for a P/E mutiple of 10.8X

Lastly, with respect to the above assumptions, we would revisit some of the historic information we discussed above by reviewing **Table 10** and **Table 11** below:

Table 10.

From Publication 5

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Pool Study 21

RACCOON LAKE FIELD
Marion County

EXPLORATION METHOD LEADING TO DISCOVERY Seismographing
STATUS OF FIELD Producing

DISCOVERY WELL

	Mississippian	Hunton
NAME	Texas Co. No. 1 Franke-Meyer Unit	Texas No. 10 C. Langenfeld
LOCATION	3-1N-1E, NW-SW-SE	3-1N-1E, NW-SE
COMPLETION DATE	July 1949	October 1951
ELEVATION	513 ft	477 ft
CASING	10-in. to 83 ft, 7-in. to 1,914 ft	10-in. to 73 ft, 7-in. to 3,376 ft
TREATMENT	Shot	Perforated and acidized at 3,256-3,320 ft
TOTAL DEPTH	2,067 ft	3,385 ft
INITIAL PRODUCTION	214 BO in 24 hr from Rosiclare and "McClosky"	109 BP/101 BW in 24 hr

PRODUCING STRATA Cypress, "Benoist," "Ohara," Rosiclare, "McClosky" (all Mississippian); Devonian; Silurian.
DEEPEST STRATIGRAPHIC UNIT PENETRATED Silurian, several wells in 3-1N-1E
KIND OF TRAP Stratigraphic - a Silurian reef
PRODUCING AREA (Reef)
PROVED 230 acres
PROBABLE 230 acres
APPROVED SPACING 20 acres
NUMBER OF WELLS THAT PRODUCED 16 (plugged in 1967)
NUMBER OF DRY HOLES 10
THICKNESS AND LITHOLOGY OF RESERVOIR ROCK 0 to 15 ft of dolomite in the Geneva Member (Devonian); reef thickness unknown.
CHARACTER OF OIL Not known
INITIAL FIELD PRESSURE Some wells flowed; some recorded slightly over 1,000 lb BHP on a DST.
COMPLETION PRACTICES Pipe set through pay and perforated; well then acidized.
MARKET FOR OIL Texas Pipeline
NOTES Waterflooding begun: 1961, "McClosky" and Rosiclare
1965, Cypress and "Benoist"

See figures 64, 65, and 66.

From Publication 5

RACCOON LAKE FIELD
Oil Production, bbl

Year	Annual	Cumulative
1949	122,556	122,556
1950	368,069	490,625
1951	222,768	713,393
1952	660,443	1,373,836
1953	549,844	1,923,680
1954	320,803	2,244,483
1955	193,544	2,438,027
1956	157,333	2,595,360
1957	135,339	2,730,699
1958	99,111	2,829,810
1959	79,713	2,909,523
1960	71,268	2,980,791
1961	60,720	3,041,511
1962	48,442	3,089,953*
1963	41,240	3,131,193
1964	48,009	3,179,202
1965	40,558	3,219,760
1966	36,620	3,256,380
1967	27,665	3,284,045
1968	23,164	3,307,209
1969	14,209	3,321,418
1970	12,267	3,333,685
1971	11,500	3,345,185
1972	10,500	3,355,685

* Secondary recovery begun.

From Publication 2

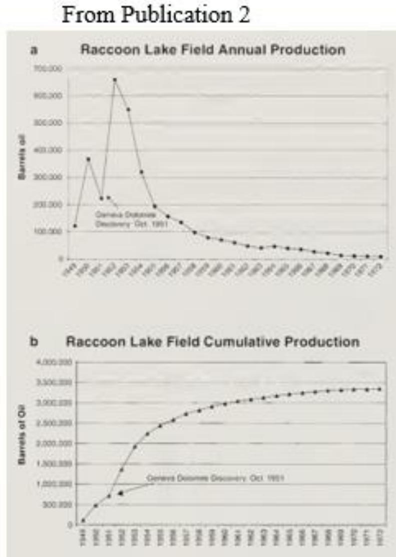

Figure 17 (a) Graph of annual production from the Raccoon Lake Field showing the rapid increase from 220,000 barrels of oil to 660,000 barrels of oil with discovery of the Geneva Dolomite reservoir. (b) Cumulative production curve shows that much of the production in the Raccoon Lake Field occurred in the five years following the discovery of the Geneva Dolomite reservoir.

Table 11.

From Publication 5

Pool Study 23

SANDOVAL FIELD
Marion County

EXPLORATION METHOD LEADING TO DISCOVERY Discovery of oil seep in a coal mine
STATUS OF FIELD Abandoned

DISCOVERY WELL

	Pennsylvanian	Devonian
NAME	Marion County Oil Co. No. 1 Sherman	Southwestern Oil & Gas No. 21 Benoist
LOCATION	9-2N-1E	8-2N-1E, NW-NW-NE
COMPLETION DATE	November 1, 1908	December 20, 1938
ELEVATION	Not known	517 ft
CASING	Not known	5 3/16-in. to 2,896 ft
TREATMENT	Not known	Natural
TOTAL DEPTH	Not known	2,926 ft
INITIAL PRODUCTION	Not known, but from Pennsylvanian sand.	319 BO flowing in 19 hr

PRODUCING STRATA Cypress, "Benoist" (both Mississippian); Geneva (Devonian)
DEEPEST STRATIGRAPHIC UNIT PENETRATED St. Peter Sandstone (Ordovician), TD 5,023 ft, 4-2N-1E, Martin No. 1 Robinson
KIND OF TRAP Silurian reef is called a stratigraphic trap whereas pay zones draped over reef are structural traps. Geneva Dolomite Member draped over reef. No Silurian production.
PRODUCTIVE AREA (Reef only)
PROVED 280 acres
PROBABLE 280 acres
APPROVED SPACING 20 acres now; none when most of the field was drilled
NUMBER OF WELLS THAT PRODUCED 33
NUMBER OF DRY HOLES 11
THICKNESS AND LITHOLOGY OF RESERVOIR ROCK Geneva Dolomite about 15 ft thick, draped over reef. Three sands also produce over dome.

CHARACTER OF OIL

Temperature (F)	100°	77°	50°
Viscosity (cP)	4.81	6.54	12.89

COMPLETION PRACTICES In most wells, pipe set on top of pay and well then acidized.
MARKET FOR OIL Sohio Petroleum Co.; Ashland Oil, Inc.

REFERENCES AND NOTES

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Brownfield, R. L., 1954, Structural history of the Centralia area: Illinois Geol. Survey Rept. Inv. 172, 31 p.

Hoover, W. F., 1944, Correlation of subsurface Devonian of Sandoval pool, Madison Co., Illinois, with Devonian outcrop of southwestern Illinois: Am. Assoc. Petroleum Geologists Bull., v. 28, no. 10, p. 1528-1534.

Moulton, G. F., and A. H. Bell, 1929, Three typical oil fields of the Illinois region, in Structure of typical American oil fields: Am. Assoc. Petroleum Geologists, v. 2, p. 115-141.

Spitznagel, K. A., 1939, Sandoval Devonian structure: Oil and Gas Jour., v. 38, no. 18, p. 23-24.

Squires, Frederick, and A. H. Bell, 1943a, Water flooding of oil sands in Illinois: Illinois Geol. Survey Rept. Inv. 89, 101 p.

See figures 70, 71, and 72.

From Publication 5

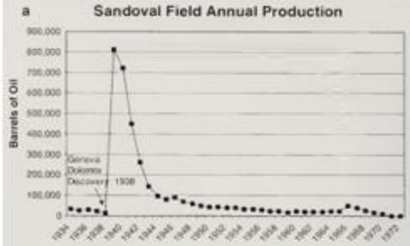
SANDOVAL FIELD
Oil Production, bbl

Year	Annual	Cumulative
1934	34,300	2,550,000
1935	27,000	2,577,000
1936	30,160	2,607,160
1937	23,800	2,630,960
1938	15,000	2,645,960
1939	814,000*	3,459,960
1940	721,000	4,180,960
1941	450,000	4,630,960
1942	263,000	4,893,960
1943	144,000	5,037,960
1944	96,000	5,133,960
1945	81,000	5,214,960
1946	89,000	5,303,960
1947	71,000	5,374,960
1948	61,000	5,435,960
1949	52,000	5,487,960
1950	44,000	5,531,960
1951	42,000	5,573,960
1952	39,000	5,612,960
1953	40,000	5,652,960
1954	33,000	5,685,960
1955	35,000	5,720,960
1956	29,000	5,749,960
1957	25,000	5,774,960
1958	25,000	5,799,960
1959	17,000	5,816,960
1960	22,000	5,838,960
1961	21,000	5,859,960
1962	20,000	5,879,960
1963	21,000	5,900,960
1964	22,000	5,922,960
1965	24,000	5,946,960
1966	51,500	5,998,460
1967	40,400	6,038,860
1968	27,400	6,066,260
1969	17,800	6,084,060
1970	9,800	6,093,860
1971	0	6,093,860
1972	0	6,093,860

* Hunton production began.

From Publication 2

a Sandoval Field Annual Production



b Sandoval Field Cumulative Production

Figure 18 (a) Graph of annual production from the Sandoval Field showing the large increase following discovery and development of the Geneva Dolomite reservoir. (b) Cumulative production curve in Sandoval Field also shows a significant increase in production following the discovery and development of the Geneva Dolomite reservoir.

There are a few items in Tables 10 and 11 that we think are worth noting with respect to the variables we used in the Valuation and Sensitivity Analysis we provided above. First, Tables 10 and 11 reference two Illinois Basin fields (albeit in Illinois) referred to as Racoon Lake and Sandoval. As some of the associated narrative suggests, each of these fields produced from Geneva Dolomite arouns Silurian reefs. Notice in each case we circled (in **BLUE**) some information that notes the number of producing wells versus those that were dry. In the case of Racoon Lake, they drilled 26 wells of which 16 produced (60% success) while at Sandoval they drilled 44 wells of which 33 produced (75% success). Those numbers compare favorably to the scenarios we provide in terms of drilling success. In addition, we also circled (in **RED**) the initial flow rates at Sandoval. While the associated table for Racoon Lake did not reflect intial flow rates, the included narrative to the document notes: "*The Geneva Dolomite reservoir was discovered with the drilling of the Texas No. 10 C. Langenfeld in Sec. 3, TIN, R1E, in 1951 at a depth of 3,385 feet. Initial daily production from the well was 109 barrels of oil".* Here again, the results from these particular fields compare favorably to variables provided in our sensitivity analysis above, as each of these fields reflected intial flow rates well beyone the outer boundaries of our matrices (60 barrels per day).

Management Overview

- ***Howard Crosby- Founder/CEO***

1975 graduate of the University of Idaho, early in his career Mr. Crosby worked as a technical editor for Westinghouse before joining United Nuclear Industries in 1981. UNC was a major uranium producer, and Mr. Crosby worked for a division that provided direct assay instrumentation to industry. During his time with UNC he visited mining projects on three continents.

Throughout the 1980's Mr Crosby worked on financing various projects in natural resources and technology until forming his own consulting company, Crosby Enterprises in 1989. Through the 1990's Mr. Crosby consulted with various companies in both oil and gas and mining, and in 2001 he assumed the role of CEO of Cadence Resources.

At that time, Cadence was a tiny OTC listed company with a market capitalization of less than $1 million. Initial efforts were focused on developing oil production in Wilbarger County in north Texas along an area known as the "Red River Arch." Numerous producing wells were put on production over the next four years, with ever increasing cash flow as the oil price moved from $20/barrel to over $60/barrel. In addition, Cadence developed a large gas field in Desoto Parish LA, near Shreveport, with deep gas wells in the Hosston and Cotton Valley formations. During this four year period, the market capitalization went from under $1 million to over $400 million. In early 2006, the company was sold in a share exchange to an AMEX listed oil and gas company.

Also in 2004, Mr. Crosby was a co-founder of High Plains Uranium, where he served as a non executive director until the company was sold to Energy Metals in 2006. In the interim, High Plains raised some $20 million and was listed on the TSX.V. At the time of the acquisition by Energy Metals, the market value of High Plains had increased 5X to over $100 million.

In June of 2006, Mr. Crosby along with his longtime partner were successful in acquiring the 2nd largest primary silver mine from Couer d'Alene Mines for $15 million. The Galena Mine near Wallace Idaho was in a mine out mode at the time, and US Silver was formed and over $60 million was raised on the Toronto Stock Exchange to redevelop the mine. Over the next three years, silver reserves were increased five fold by drilling, *production was resumed and the mine remains a major producer to this day. Mr. Crosby ended his active participation around 2009.*

In more recent years, Mr. Crosby was active in pursuing a large titanium deposit in Chile, as well as assisting in the redevelopment of the historic Bunker Hill Mine near Kellogg, Idaho, and assisted in the formation of Blackjack Silver, which is a private company in the process of developing major silver-lead-zinc resources in Butte, MT.

LGX Energy, formed this past fall, represents Mr. Crosby's return to the oil and gas industry to pursue an outstanding opportunity in the Illinois Basin in southern Indiana. It is his belief that this represents a major underdeveloped oil and gas resource in a favorable business-oriented state at a time of increasing demand for oil in an environment of rising oil and gas prices.

- ***William Deneau***

William W. Deneau served as the President and Chairman of the Board of Directors for publicly traded, Aurora Oil & Gas Corporation from 2005 until 2009. His entry into Oil & Gas began in 1984 which his employment with a Michigan company as their land manager. In 1987, he founded White Pine Land Company in Michigan (nka Basin One, Inc.). Their real estate work for oil company clients covered Michigan, Ohio, Indiana, Illinois and Kentucky. In 1997, Deneau along with John Miller and Tom Tucker formed Aurora Energy, Ltd. Aurora Energy merged with Cadence Resources and these companies became Aurora Oil & Gas Corporation. After leaving Aurora in July 2009, Deneau and Tucker formed Walden Energy Resources, LLC and they put their effort into prospect development in the Michigan basin. Additionally, Deneau serves as President of Edison Supply Company, Inc. which represents the Linear Kinetic Cell tool which assists in paraffin and scale treatment in oil wells.

- ***Jerry Blaxton***

Mr. Blaxton achieved a degree in geology from Central Michigan University, taught geology at university level, published articles/papers in geologic and geophysical publications, and presents at professional conferences. Mr. Blaxton is a 40-year veteran of utilizing seismic data for oil and gas exploration, as well as USEPA investigations.

After 12 years of experience processing and interpreting seismic data at Woods Geophysical, Mr. Blaxton founded Integrity Geophysical Services in 1994 and has provided geophysical and geological services to find hydrocarbons in all basins of northern and eastern United States. Formations targeted for oil and gas development with seismic data, include Berea, Traverse, Dundee, North Vernon, Salem, Silurian, Richfield, Marcellus, Devonian Shales, various Mississippian sands, Trenton/Black River, Knox, PdC, Rose Run, and Trempealeau. Seismic innovation and research into synthetic seismograms, deconvolution, statics, migration, 3D modelling, and fracture velocities have enabled Mr. Blaxton to greatly advance his capabilities in seismic data interpretations.

- ***John V. Miller, Jr.***

John V. Miller, Jr., age 63, has been extensively involved in funding, drilling, and developing oil and gas fields since 1988. Mr. Miller was a driving force in funding and managing development of 500+ wells in the Michigan Antrim Shale production trend, along with various exploration and drilling projects in central Oklahoma, the Williston Basin, Louisiana, Texas, Ohio, and Indiana. Mr. Miller worked with Gas Research

Institute (now Gas Technology Institute) to gather data and evaluate the shale plays of Indiana, leading to the funding of the first horizontal well drilled in the Illinois Basin targeting the New Albany Shale.

Mr. Miller owns a consulting company, Miller Resources, Inc., established in 1994, actively securing mineral rights in various oil and gas plays around the USA and has recently been participating as a consultant with other companies in utilizing advanced 3D technologies to find and develop oil fields, including active programs in Ohio, Gulf Coast regions, Illinois Basin, and Michigan Basin.

- ***Thomas W. Tucke***

Thomas W. Tucker began his oil and gas career in 1982 when he and his father started Jet Oil Corporation whose work in the Michigan basin with Niagaran reefs was successful in the northern and southern reef trends. Niagaran reefs are found with seismic data, processed and interpreted. In 1997, Tucker, John Miller and William Deneau, formed Aurora Energy and eventually merged with Cadence Resources. These companies became publicly traded Aurora Oil & Gas Corporation in 2005. Tucker served as Vice President of Operations for Aurora Oil & Gas Corporation from 2005 until 2008. In 2013, Tucker and Deneau formed Walden Energy Resources, LLC and they put their effort into prospect development in the Michigan basin.

- ***Shane G. Miller***

Land and Field Operations Consultant

Shane Miller, age 41, will be managing land and field operations for Adler Energy and LGX Energy Corp. Mr. Miller was specially trained for natural gas production operations in a large Michigan natural gas drilling project. Shane has worked on oil and gas projects in numerous capacities since he was in high school, including landman and title services on projects in Michigan, Indiana and Kansas.

Since drilling the first well in a Michigan shale gas project, Mr. Miller has managed the drilling of more than 100 gas and/or oil wells, the installation and operations of 50+ miles of pipeline, and the construction of large Antrim gas facilities along with oil production facilities.

Summary and Conclusion

To summarize, LGX was founded by a team of energy industry veterans with specific experience in and around the Illinois Basin. The Basin as well as other portions of Indiana has at times over the past century been a meaningful producer of oil and gas. While the region has been a producer, most of that development has occurred in shallower formations and despite its historic success it has largely been underdeveloped, especially with respect to technologies (seismic for instance) that has been applied more aggressively in other basins/regions around the country. We submit, aside from a lack of technology application, one of the reasons for the area’s underdevelopment likely stems from its lower production profile vis-à-vis other producing regions, which we suspect lead to capital deployment away from the Illinois Basin.

Clearly, the reasons for the region’s lack of development are likely more complex than we are suggesting here. On the other hand, a new variable has emerged that we think also may shine a light o the region despite its lower production profile, and that variable is oil prices. In short, there are likely many projects around the country that make sense at

$100+ oil, that may not make sense at sub $60 oil (for instance). That said, to make them happen someone needs to provide the capital and the initiative to make them work. In a nutshell, that is perhaps LGX's mission.

Recognize, we are not suggesting that higher oil prices suddenly made an exploration foray into the Indiana side of the Illinois Basin a no-brainer. Clearly a lack of meaningful data (seismic for instance) adds marked risk to the process, and while higher oil prices may help that calculus, they may still not justify it. From another perspective, while the seismic data is clearly important, a "lack of meaningful data" can be solved other ways as well. For instance, we would argue that the LGX team's "tribal knowledge" of the area is of considerable value, and that includes expertise in land acquisition and operations. We submit, while anyone can provide a reasonable estimate of what it might cost to shoot 300 hundred or 400 miles of seismic in the Illinois Basin and as such put a value on the Company's asset in that regard, we may not be able to give you the same objective value of the LGX team's grey matter. We believe it provides marked value regardless of our inability put a defensible number on it.

Given the above, if we look at this project in terms of a checklist that would need to be completed before a decision to pursue it might be made, what would that checklist look like?

1) Higher energy prices. As we noted, higher energy prices make most energy projects more attractive on the face.

2) Access to data, and perhaps more specifically 2D and/or 3D seismic. Succinctly, despite higher energy prices, we doubt LGX would be embarking on this project had this data not been part of the acquisition.

3) A team of industry people familiar with the area and armed with knowledge that can fill in the gaps that even access to seismic and other associated data may not provide. We think that would include knowledge of storage, transportation and other logistic issues in the area, as well as local land acquisition expertise and ultimately operating knowledge and others. In short, if finding a viable resource is one side of the equation, the other is being able to finish and ultimately produce the resource.

4) Existing production to support working capital through anticipated new cashflow/production. As we noted, the Company's acquisition of production along with the seismic data has provided a base of cashflow to support operating overhead during the startup phase. While that cashflow is not substantial, *it is enough* (especially given oil prices that are considerably higher than when they first negotiated the acquisition) to address much of the current overhead, which means that much of the new capital will go into the ground. That brings us to the final point on the checklist.

5) Access to capital. As we noted, the Company has raised (is raising) what we think will be something close to $2 million in their "Friends and Family" round, which we think should allow them to spend some money interpreting/enhancing the existing 2D seismic, identify the most promising targets, and drill at least a handful of wells to test their data/theories. Obviously, their path forward will be determined in part by the outcomes of those first few wells.

Recognize, while we think we have articulated a relatively constructive account of LGX's prospects, we submit, there is clearly considerable risk in their project, and that includes macro risks (forward oil prices for instance) as well as several unsystematic risks. Those include their success in finding resources in the first place, their ability to procure the rights to resources they do identify, their ability to cost effectively lift/produce them and a host of others. Succinctly, the oil patch is not a good place for risk averse investors.

That said, taking those risks into consideration, as we argued above, in the context of what we think the value of the acquired seismic might be (along with the purchased production), we think LGX has priced its F&F round appropriately in the sense that the pre-money valuation of the round *may be* less than or at least close to the value of the acquired (pre-money) assets. Setting aside the prospects for success, that is typically a good spot for an investor to start from. Again, that does not speak to the ultimate success of the project, but it does provide a good starting point.

In addition, while our valuation/sensitivity analysis reflects a wide array of potential outcomes ranging from negative to markedly positive, we think the takeaway from that analysis is that while there are several things here that must come together for LGX (et al.) to be successful, the opportunity is quite open-ended, which means there is at least a foreseeable (and in our view defensible) path to extraordinary returns/results.