Transcript of
Southwestern Energy Company
Second Quarter 2017 Earnings Teleconference Call
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Participants

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Bill Way - President & Chief Executive Officer
Jennifer Stewart - Chief Financial Officer
Jason Kurtz - VP of Marketing and Transportation
Jack Bergeron - SVP of Operations
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Analysts

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Presentation

Operator
Greetings, and welcome to Southwestern Energy Company Second Quarter 2017 Earnings Teleconference Call. At this time, all participants are in a listen-only mode. A brief question-and-answer session will follow the formal presentation. In the interest of time, please limit yourself to two questions. Afterwards, you may feel free to re-queue for additional questions. [Operator instructions]. As a reminder, this conference is being recorded.

It is now my pleasure to introduce Michael Hancock, Vice President of Investor Relations for Southwestern Energy Company.

Michael Hancock - Vice President of Investor Relations
Thank you, Rob. Good morning and thank you for joining us today. With me today, are Bill Way, our President and Chief Executive Officer; Jennifer Stewart, our Chief Financial Officer; Jason Kurtz, our Vice President of Marketing and Transportation; Jack Bergeron, our Senior Vice President of Operations; and Paul Geiger, Senior Vice President of Corporate Development. If you've not received a copy of last night's press release regarding our second quarter 2017 financial and operating results, you can find a copy on our website at swn.com.

Also, I'd like to point out that many of the comments during this teleconference are forward-looking statements that involve risks and uncertainties affecting outcomes. Many of these are beyond our control and are discussed in more detail in the risk factors and the forward-looking statements section of our annual and quarterly filings with the Securities and Exchange Commission. Although we believe the expectations expressed are based on reasonable assumptions, they are not guarantees of future performance, and actual results or developments may differ materially.

We may also refer to some non-GAAP financial measures, which help facilitate comparisons across periods and with peers. For any non-GAAP measures we use, a reconciliation to the nearest corresponding GAAP measure can be found in our earnings release available on our website.

I'll now turn the call over to Bill Way to discuss our results and recent activity.

Bill Way - President & Chief Executive Officer
Thanks, Michael. Good morning everyone and thanks for joining us on our call today. We really are delighted to have you on the call to discuss the latest achievements here at Southwestern and some of the strong differentiating results that our very highly talented teams across the country have delivered throughout the portfolio.

As you saw in last night's release, we once again delivered the solid results that we guided back in February. We did this, as we promised, while investing within cash flow and for our fully funded capital plan. We continue to monitor commodity prices and remain committed to adjusting our capital program to align with price changes as we move into the second half of 2017 and beyond.

As we continue to demonstrate, we believe that focusing on the highest return projects and investing within cash flow results in differentiating shareholder value. Production growth is an outcome of our plans, not a driver for them. As we look forward, we believe that the increasing demand and the lower than anticipated supply response that we're currently seeing has been evidenced by the recent trend of strong weekly gas storage reports has yet to be reflected in the forward curve.

The billions of dollars being invested in new gas driven power plants and industrial facilities, coupled with continuing opportunities of increased exports to Mexico and from LNG, are expected to increase demand by over 10 billion cubic feet per day over the next four years.

With the decline of many basins outside of Appalachia, additional drilling will need to be incentivized to meet this growing demand. One source of this needed supply is expected to be associated gas from the Permian. However, in this current oil price environment, and with takeaway solutions from the region being required but being fully subscribed, we think the supply will need to be supplemented by other regions of dry gas.

In addition to the encouraging outlook for natural gas prices, the basis differential outlook also continues to improve due to the momentum on pipeline infrastructure in the Northeast United States. As you know, we now have a quorum at the FERC and this quorum should facilitate the approval of certificates to initiate construction on approximately 10 Bcf per day of new takeaway capacity in addition to the 5 Bcf per day of capacity that is currently under construction, increasing the total takeaway from the Northeast region by approximately 15 billion cubic feet per day between now and 2020.

Rover, alone, which is getting a lot of attention right now in the press due to its impending end service date, we will deliver capacity of over 3 billion cubic feet a day once it gets full. While there are many delays talked about in the press around Phase 1 of this project, we want to remind everyone that our 200 million a day of firm capacity is on Phase 2 which is still expected to be online near the end of 2017, as we have modeled. We do not anticipate any impacts to our development schedule should there be a delay in Phase 2 as we proactively identified alternative operations for additional capacity on a short-term basis, if we need it.

Focusing on our Northeast Appalachia asset for a moment, during this quarter, we added approximately 140 million cubic feet per day of new firm takeaway capacity at an average cost of only a $0.10 per Mcf, substantially lower than our already impressive low cost transportation portfolio out of the area. This new capacity, which facilitates further growth, will deliver volumes to be priced off of the Dominion Appalachia Index, which is expected to improve even further from historic levels as additional Southwest Appalachia pipelines come online.

Let me switch now to the quality performance of our portfolio. The company had a total net production of 222 Bcf equivalents in the second quarter, a 9% increase compared to the first quarter of 2017 despite third-party gathering issues. The company's operations were impacted in the second quarter by a one-off delay in the installation of a small third-party field gathering line in Susquehanna County that was expected to come on in early 2017 and the third-party compressor station that unexpectedly went off line for repair in late June.

We are leveraging our differentiating midstream gathering expertise, our commercial optimization capabilities and our flexible gathering systems across the state and working closely with our third-party gatherer to diligently implement measures mitigating this operational downtime. As I've said before, these are one-off events, are not structural changes and do not change our development plans.

Now, let me turn over to Jennifer to discuss some of our financial highlights.

Jennifer Stewart - Chief Financial Officer
Thanks, Bill, and good morning, everyone. I'm excited to be here today and for those of you that I haven't had a chance to meet, I look forward to meeting you on the road soon.

Strengthening the balance sheet remains a key focus for the company, and to that end in the second quarter of 2017, we retired our remaining 2018 senior notes and will retire the 40 million in 2017 senior notes upon the maturity in the fourth quarter. While we have no other near-term maturities, we will continue to look for ways to opportunistically de-lever or extend our maturities in order to further strengthen our liquidity and credit profiles.

As Bill mentioned, financial discipline drives our decision-making process and our robust hedging program provides protection of cash flows and ensures targeted returns. We made additional progress on building our hedge book during the second quarter, as we now have over 400 Bcf of 2018 production hedged at an average swap of a purchased put strike price of approximately $3 per Mcf with upside exposure on approximately 72% of those protected volumes up to $3.39 per Mcf. The company also has over 100 Bcf hedged for 2019 at an average purchased put strike price of $2.95 with upside exposure up to $3.32 per Mcf.

Our 2018 and 2019 positions continue to be predominantly collars in order to retain upside exposure to expected improvements in commodity prices. We continue to see the benefits of an improving commodity price environment this quarter. Compared to the second quarter of 2016, realized natural gas prices, excluding hedges, increased 94% to $2.35 per Mcf. Improvement also continues to be seen with NGL pricing. Our realized C3 plus NGL prices were $21.62 per barrel including transportation costs, up 46% from $14.78 per barrel in the second quarter of 2016. Our total NGL barrel realization, inclusive of transportation charges, was $11.25 per barrel, up 76% compared to $6.41 per barrel in the second quarter of 2016.

I will now turn it over to Jack for an operational update.

Jack Bergeron - SVP of Operations
Thanks, Jenifer, and good morning, everyone. In the second quarter, we invested approximately $318 million in our E&P business and had total net production of 222 Bcf, an increase of approximately 9% compared to the first quarter of the year. This includes an increase in our Appalachian Basin of 140 Bcf or 14%. We're continuing to progress our technical learnings and apply these learnings across our portfolio. We have been achieving our leading operating capability related to extended laterals, lateral placement, completion intensity and optimized flow techniques. These achievements represent a step change in how the company is approaching well design to maximize value and again confirm Southwestern as a leader in US shale gas development.

For example, in Northeast Appalachia, the company has increased the average lateral length of its wells by over 10% since 2015, while staying in the targeted interval over 90% of the time, a substantial improvement from the approximately 75% precision back in 2015. Two of these wells were recently completed with average lateral lengths of over 11,000 feet. The most recent example of this is the Seymour 1H, which is demonstrating productivity among the top 10% of the company's wells ever drilled in Bradford County on a CLAT-adjusted basis. This well with a lateral length of over 12,000 feet delivered an initial production rate of 37.7 MMcfe per day.

The company is also seeing continued success with its increased completion intensity testing across its acreage. In Southwest Appalachia, the Ritchea pad in Wetzel County continues to outperform its offsets by approximately 25% after the first 160 days of production. Two of the wells on this pad were completed with 3,500 pounds of profit per foot with 140 foot stage facing. Additionally, in Marshall County, we placed the Michael Dunn pad online in the second quarter of 2017. After over three months of production, this four well pad is at a flat pad rate of 38 MMcfe per day, 44% of which is liquids, at an average flowing casing pressure of 2,400 psi. Early indications suggest the new completion designs are outperforming the old standard completion design by 25%.

The continuous improvements made in our core acreage positions were also delivering benefits in our delineation testing throughout our portfolio that could unlock additional value. In Southwest Appalachia, our first company drill of Utica well continues to perform as a top quartile well with cumulative production of over 2 Bcf in its first six flowing months. The well is currently flowing at a flat rate of 15 MMcfe of gas per day with a casing pressure of approximately 6,000 psi. And based on our extensive analysis, it's projected to remain flowing at this rate until sometime in 2018. We have recently finished drilling and completing our second Utica well in Washington County, and are in the process of completing the final steps of bringing this well online and expect to have results later this year.

In the Fayetteville, we progressed our learnings with the Moorefield where we brought two additional wells online this quarter, one of which encountered a fall which has resulted in increased water production and limited early stage productivity. The second well confirmed our geologic understanding and was brought online with a 5 MMcfe per day, 30th day rate, and an initial EUR of over 5 Bcf. We expect to bring additional delineation wells online throughout the remainder of 2017.

This concludes our prepared remarks. We'll turn it back to Rob, who will explain the procedure for asking questions.

Operator
Thank you. We will now be conducting a question-and-answer session. [Operator instructions]. Our first question comes from the line of Scott Hanold with RBC. Please go ahead with your question.

Q: Bill, you talked a little bit about, and you wrote on it in your release, some of the actions you took to mitigate some of the downtime in the Northeast. Could you give a little bit more color on exactly what you're doing? As we think of that, is this something that you feel comfortable that it's going to be available to you going forward? What's the cost of these options?

Bill Way - President & Chief Executive Officer
Yes, let me start with the slow pipeline jumper that we talked about. If you imagine going out into the extents of the gathering systems and looking at hydraulic opportunities for linking them together, so we're not anywhere near a major trunk line, these are out in the gathering system. There was a delay of getting a permit. So the pipeline will get put on, it's only a mile long or two miles long. It's not even a major trunk line. That will get sorted, be done.

Our gathering system has a number of tie-in points, if you look at that one alone. But if you look at our company, we've got gathering systems and capabilities all over the state. So we can optimize and move things around, so that one-off gathering issue is there, it'll be finished, there's not anything holding that up.

The compressor station issue had to do with some vibration issues at the station. Station has been nearly completely rebuilt. They are working on the final pieces of equipment that have to do with pulsation and dampening. They'll get that done. The machines are set, the roof's being put on, and I mean it's getting done. So we also have flexible delivery from our network of marketing opportunities and firm transportation that enables us to move volume around which enables us to, again, mitigate any issues with from the gathering site going to that compressor station.

So, again a one-off issue unfortunate for the company, the compressor company, but we moved it around. The cost to mitigate all of this is really not a cost to mitigate, it's shifting deliveries from one pipeline network to another to deal with the compressor issue and moving around and seeing what further optimization we can have on our gathering system. I think in the gathering system, and it's actually a sort of a wake-up to you that says are there further ways we can optimize this gathering system and optimize gas flows for the future, as we get past all of this.

As I said, not structural, it doesn't change our development plan, and the cost to us we've not put any cost into it actually, except manpower time from our marketing team to our field folks. Having said that, we have a great deal of marketing expertise, I mean gathering expertise, and we have that from the Fayetteville and from our Northeast presence. And we have joined together with our gathering company, the third-party gathering company, and are supporting the efforts to get this done. Part of that is helping accelerate schedules, etc. We look at these as cooperative efforts with all of our third-party suppliers.

Q: Okay, appreciate that color. And then my follow-up question is on the Moorefield, the well that encountered default. As you do the postmortem on that, is there any indication that you all had that that could be a risk or did you learn anything that can be—when you look at that 150,000-acre bubble, how much of that do you think could be impacted by that?

Bill Way - President & Chief Executive Officer
I don't think we actually know, there's two kind of things. One, there's a fault we encountered, two is how close you get to it as you're drilling. So, you'll recall back in the early days when we were trying to figure out how do Moorefield, it's one of the big question marks where is the landing zone and how far do you stay away from that so that you don't encounter the water. When we encountered this fault, there was a bit more water. We think we got a bit too close, so we'll just go back and validate the model and continue forward.

We haven't changed our view on the expanse of this nor have we proved it all up, that's part of the delineation program. So I want to give you a balanced answer. We'll keep moving forward. The other well was fine and was positioned appropriately away from any kind of water source and so there is not a major shift here. We got several more wells to finish off before we can declare that. But our intention and our plan is still to move forward. And as you would know so that I complete the circle, we put all of this kind of capital investment in the big prioritization bucket, look at how it's prioritized, timing, etc. and go forward. So it's just part of our normal ongoing way we work.

Q: Okay. And could you remind me, the Fayetteville geology, is that pretty subtle? Or do you encounter much fault in the Fayetteville formation?

Jack Bergeron - SVP of Operations
Scott, this is Jack. We have 3D across the whole Fayetteville, some faults are smaller than seismic would show up, and the geology, the faults are easily seen. It's really how close you can get to them and this time we got too close to [indiscernible] fault.

Operator
Our next question comes from the line of Charles Meade with Johnson Rice. Please proceed with your question.

Q: I'd like to start with a big picture question on your strategy. And it goes, maybe a good place to start is in your prepared comments, and excuse me if I'm paraphrasing a bit here. You said that growth is an outcome for you, not a goal. Could you talk about what actually the goals or the drivers of your behavior are? And perhaps, comment on whether you see them still fitting with the macro outlook that we're living in and if there's been any shifts are adjustments on your part?

Bill Way - President & Chief Executive Officer
Let me start by taking part of the paraphrasing and bringing back the fact I said production growth. Drilling, if you get into a place where you're exceeding cash flow or you get into a place, and we're not there now, but if you get into a place like back in early 2016 where there aren't economics to support drilling and completing wells, gas is $1.70, then you don't drill just so that you can realize production growth. We are all about, our strategy is all about, value growth from economic projects through rigorous financial discipline, stringent capital allocation against economics, un-hedged, in priority order, premier asset optionality. We talked a little about that this morning being able to leverage our marketing asset and our gathering assets to try to mitigate unanticipated third-party things, and then always being on an increasing capital efficiency and margin drive.

So our objective and our strategy is economic value growth, it's not changed at all. I think you'll see as we move through this quarter we're reporting and the quarters going forward, it's all about investing within the cash flow, having that cash flow be measured against strip, and having a proper hedge program using tools that mitigate the downside and tools that allow for upside, as gas moves around for variety of reasons. And that is what we're all about, been about and that's what we're doing, and leveraging the technical capability of our organization in an integrated way to unlock additional potential out of these large scale assets.

Our strategy is focused on large scale assets; as we go forward in time, you'll see us continue to focus on those. And as we look for future opportunities and how we might take the current asset portfolio forward, we'll work those and get that out there. But my point mainly to drive is production growth, whether that's liquids or gas or anything is not a main driver because you got to put economics in there, this is about value generation.

Q: Bill, it's a good to hear that again from you guys. And then if I could ask an asset level question again, back on the Moorefield. Could you give us a recap or maybe a summary of how you're viewing that zone at this point? Where is it perhaps in the relative maturity or where is it on the S-curve of your learning about it? An I now you mentioned you're going to have some more activity there in the back half of '17, can you give us an idea of how many more well results you're going to share and perhaps how it fits into that into your view of the zone?

Bill Way - President & Chief Executive Officer
Sure, let me start with the greater Fayetteville complex. So I'm talking about Fayetteville in its broadest sense. Our objective in Fayetteville is to work from a commercial, technical, operational perspective to bring Fayetteville's breakeven costs, bring Fayetteville's economic value drivers, higher and higher and higher, and expand the opportunities for that resource phase. We went through and looked and found the Moorefield, under the Fayetteville, there's other benches under the Fayetteville that we look at, the team studied, looked at the optimal geology, optimal reservoir characteristics.

We went on a test program and figured out that on a projected basis we probably had 115,000 acres of first tier looking acreage we wanted to go test. So we set out on a delineation program. These wells are a bit deeper; they're a bit higher pressure. But what happens with that, assuming you can stay away from the water, is the wells have higher EURs and only slightly higher cost relative to the higher EURs and position them in the portfolio quite favorably. And so we began with a single pad test that proved up only a small amount of acreage, but it proved the reservoir model. And then we have gone to spreading out across the remaining 100,000 acres that we hadn't tested yet and put a campaign together.

We've got about four wells in the test program for the remainder of the year. As you would expect me to say, those four wells, while we want the data and we want to understand what it is, as we continue to adjust our cash flow and monitor what's going on, whether that's four or three or two or five, it's going to just be on a cycle like that. We are optimistic that we understand the model because of the track record we've had so far, but we'll see where we go from there.

We've built, we have all of the gathering network, everything that you need because these are in the same field being drilled under deeper in the horizon. So being able to go out, capture them, add additional gathering revenue to the gathering company, add additional inventory to the company, that potential is there and that's what we're trying to prove out.

Operator
Our next question comes from the line of Dan McSpirit of BMO Capital Markets. Please proceed with your questions.

Q: Bill, the announcement to hire an experienced individual to head up Corporate Development before maybe announcing the same with respect to the open CFO position may carry some weight unless of course Ms. Stewart permanently fills that role. If you could, please discuss the decision to hire Mr. Cecil, what he will be charged with accomplishing, and how it would ultimately translate into value creation for shareholders.

Bill Way - President & Chief Executive Officer
Sure. Let me start and back up a little bit from Mr. Cecil and just tell you that, in our company across the employee base across the country in a number of areas, we've got a lot of different technical operating groups or technical groups that are driving a lot of the changes and the things that you hear about. We have emerging

technology groups, big data groups. We've got our length to reserves, a number of those technical roles. We took the decision to bring all of that together. If you have a strategy that says leverage large scale, and you have all these different groups everywhere, well bring them all together and leverage them as a unit.

In doing that, we took one of our existing officers, Paul, who is in the room with us today, who has deep technical and operating capability and expertise to run that business, which resulted in a need for a new Head of Corporate Development. Corporate Development looks after our strategy, looks after our planning, strategic planning efforts, our commercial development, and our business development, all of those. We have known David for some time. David worked with me alongside with myself and the board and our CFO in crafting and working through all of our 2016 early days work to strengthen the balance sheet, the rigorous capital management, all of the development of that, and he's worked alongside us for some time so we know him well.

We know his strategic capabilities, his corporate finance capabilities. And when you combine those and his expertise in this business with a CFO, a COO and the rest of the leadership team, the core purpose of bringing David on was to strengthen the capability and capacity of our expertise in these areas and to deliver step change in shareholder value as we look at our strategy going forward, think about options that we may have with our overall portfolio and work to develop and strengthen the business development, commercial development and portfolio optimization efforts that we have.

So, we're very excited to have him. There's not some kind of a signal that is equivalent to him showing up, other than we're very excited that we bring yet additional capacity, additional capability to this technical effort that we're working and bring the additional capacity to the executive leadership team, who is charged with driving forward and continuously improving our strategy.

Q: I appreciate the full response there. And just as a follow-up to that just turning to the Fayetteville, the $425 million in free cash flow that's expected to be generated by both the E&P and gathering operations this year, what's the breakdown of that? Appreciating of course that there's some dependence between the two. And then just a quick follow-up to that, where is the basic line rate today on that asset?

Bill Way - President & Chief Executive Officer
Sure, Michael will jump on this for us.

Michael Hancock - Vice President of Investor Relations
Hey, Dan, it's Michael. The guidance for this year was $210 to $225 and there's a little piece of marketing in there, but that's primarily the Fayetteville gathering systems. That gives you some color on what you expect from the gathering side. And what was your second part?

Q: And the second part was the decline rate on that asset today, the Fayetteville.

Michael Hancock - Vice President of Investor Relations
It's probably exit to exit you're looking at probably like the high teens, 17% type number.

Operator
Our next question is from the line of Karl Chalabala with Stifel. Please proceed with your questions.

Q: Question for you guys on the Marcellus FT pick up, that looks to be the standard tariff in the Dominion. So I would assume that firm transport is a view on near-term growth constraints outside of FT capacity before Sunrise comes online rather than price driven. What should we be reading into the need for this versus simple spot sales into the current sales market without FT cost? And then could you also place in context with the substantial Marcellus productivity uplift you guys have been seeing the last few quarters?

Bill Way - President & Chief Executive Officer
Yes, I think, Jason will give you some of the detail here in a second, but our objective, and it has been a very solid and very beneficial strategy, is to assure flow out of that region, given all of the challenges of all of these pipelines that come on, etc., to have firm capacity, and at a $0.10, it's a great price, into the Dominion market and be able to assure movement of our gas in just about any circumstance. And so as you look at our portfolio and you look

at the timing of different projects in that portfolio, just like we've done in Southwest Appalachia around Rover and no signal to our friends at Rover, we just like to proactively manage any risk that might be out there and so we took this opportunity to grab this capacity.

It does two things. It risk assures and gets us locked in, number one. And number two, it allows for further expansion of our business as you see these dramatic improvements in the deep side feeding our markets. And Jason may have some additional color on that.

Jason Kurtz - VP of Marketing and Transportation
I mean, you did a really good job, Bill. But what I would say is that capacity is on Tennessee and Millennium and it really gives us the ability to make sure that we can move all of our production and grow product through Atlantic Sunrise coming in so we can make sure that we don't get constrained in those areas.

Q: And then a less geometric question, the 12,000 foot lateral you guys put there, what kind of, in terms of looking at the Marcellus position, how does that sort of fit into the program? How many of those locations might you possibly have?

Jack Bergeron - SVP of Operations
This is Jack. From the standpoint of how many 12,000 foot locations we have, again, depending on the unit geometry, we're drilling more and more of those because the economics are better on a longer lateral. It's really a function, our average lateral length is 7,500 foot. We try to extend it where we can to do that. In that area, we have more locations, a few more locations in the area of that 37 million a day well, that we're pushing forward at this point in time.

Bill Way - President & Chief Executive Officer
I think to supplement that there's a dynamic answer here because as we can go and block up land and add to lateral lengths because they're economic, we can do so, we do that, and we do it all over the portfolio. And so you'll see these longer laterals show up in different places and it's a continuous process of blocking, trading, buying selling at the unit level to maximize those lateral lengths. And we test these long laterals and like we do most things, we want to test and assure so we will test and pilot some of these, make sure that they actually are contributing through the entire lateral, continue to build our expertise in these areas and even go further as units would allow, out much further than 12 in the future.

Operator
Our next question is from the line of Brian Singer with Goldman Sachs. Please proceed with your questions.

Q: Continuing on the topic of pricing in Appalachia and capital allocation, and in an optimal scenario where your pipeline takeaway solutions come on and local gas prices improve, how aggressively would you be in ramping up volumes both to fully fill the new pipe and to grow volumes that you're selling in the local market? What combination of local [indiscernible] prices as you run through your capital allocation would you think you need to see where we should expect essentially net growth?

Bill Way - President & Chief Executive Officer
I think obviously this is all driven by economics from individual wells and by a cash flow in the portfolio, and we do comparative. We don't allocate capital by divisions in bulk. We allocate capital by projects and it depends on where it is as we build that mix out. So, as we can see economics in this ten seconds, the Northeast assets that we have draw the highest amount of capital because they're the highest effective capital. As we talk about often that the NGL price impacts the allocation between Southwest and Northeast Appalachian areas. And so because we have our own rigs and all of that piece of the story, we can flex back and forth.

We will move forward and continue with a lot of the optimization efforts, some of which we don't even need to drill to get, as we debottleneck or work on different things but we'll continue to fill that. If you can put a timestamp on it and get a change in liquid prices—and that moves it back and forth. So we look at it as an overall portfolio versus how fast do I go here because the answer changes, the answer changes from out year pricing as well. These are three-year economic things. And so you got to take a look at and have a view on both the gas price and the liquids and the differentials.

Q: I realize it's not hard and fast for a lot of the reasons you mentioned. But, is there some minimum threshold, assuming you have cash flow capability for the company where you could say if local, Dominion itself, or [indiscernible] prices are $2.00, $2.50 or pick a number you would be wanting to allocate more capital there?

Bill Way - President & Chief Executive Officer
At a given gas price on a sustained basis, it will tell you what direction to go in terms of the capital allocation. We don't have any limit except for our desire to invest within cash flow, but there's not constraints that won't allow us to go faster here or slower there. It's again a portfolio mix of projects. And the gathering capacities, the differentials, the well economics themselves are all part of a matrix that we work through and we work through that fairly continuously.

Q: Thanks. And then my follow-up is on the Fayetteville, the Fayetteville has been in decline for a number of quarters and this quarter was flat. I wanted to see if there was something to that, if you feel like there's reasons for stability or at current capital allocation and activity, what you would expect the trajectory to look like.

Michael Hancock - Vice President of Investor Relations
Hi, Brian, it's Michael. That's really, the biggest driver there, it's a function of timing. We put a lot of wells on at the end of the first quarter which impacted second quarter. So it's probably a roughly three-rig program to hold that flat. So you could assume there's still a decline in the back half of the year with the one rig we're running.

Bill Way - President & Chief Executive Officer
And those decline rates moderate over time just as you enter the flatter part of the curve. So we track that.

Q: Thank you.

Bill Way - President & Chief Executive Officer
But we're not sitting still there, we have a full team that is focused on how do we drive economic value, margin expansion, and all of the economic metrics that we need to get the Fayetteville assets to compete with other investment opportunities we have. And there's a relentless pursuit on that, so that will change, too, as we go forward.

Operator
Our next question is from the line of Doug Leggate with Bank of America. Please proceed with your question.

Q: Bill, I wonder if you could speak to what the underlying outlook is for the Fayetteville at this point. Tremendous free cash flow still, but can you talk to your objectives for that part of your business for the time being? Are you trying to hold it flat, are you trying to manage a minimum decline rate? Give us some idea as to how you're thinking about maintaining that piece of business while you evaluate the Moorefield.

Bill Way - President & Chief Executive Officer
Yes, what we do overall in the corporation is allocate capital projects based on economics, and we do that across the piece. For Fayetteville, we have the objective to unlock additional value, whether it'd be Moorefield, whether it'd be improvement in completion drilling techniques and flow back techniques, water handling, all of that to raise the bar in LOE costs and up costs, whether it's renegotiation of transport agreements that enable us to extend our agreements in the future and lower near-term numbers. All of those things are designed to drive economic value for Fayetteville up and continue to try to work to position it to attract investment from our investing within cash flow mandate.

And so there's a number of technical, commercial, operational objectives that we're chasing and the team is incentivized to do that, and that's how we measure their performance. And so, the Fayetteville is an incredible source of cash flow that drives our business going forward in the Northeast and in testing opportunities like the Moorefield and other ventures that are present there. And so, it has a significant value to us in terms of driving our agenda going forward of economic value growth.

Q: So, what do you think the underlying decline rate looks like currently?

Michael Hancock - Vice President of Investor Relations
Yes, this is Michael. It's probably that 17% we talked about for the first year, and obviously it shallows out over the next few years it gets down to the high single digits.

Q: Okay, thank you. My follow-up, Bill, if I may, obviously, continued strong performance out of that first Utica well. Can you just speak to the longer term game plan there? What are the current constraints on that? Assuming those get resolved, how would you see relative capital allocation across the Northeast part of the business? And I'll leave it there. Thanks.

Bill Way - President & Chief Executive Officer
Yes, I think I wouldn't put a constraint on our Utica testing because everything that we need to do is something that we need to do. There's not a problem area. We drilled one, completed one, drilled and completed one and have been flowing it. The performance of that well has been exceptional, and we expect that it will run the way it is for some time as we've continued to test it. The second well same thing, drilled it, completed, got it tested and run it there where we are. The learning around us has been terrific because there's been a lot of activity. We get to see different pieces of information well. That activity has slowed a bit, and so the learning capability to learn by other wells and others has slowed.

So, we'll continue to study and analyze this. Today, our ability to drill, complete, place proppant, flow back a well, get it to be a top tier well is terrific. The well costs at this point in the cycle are higher because you load it down with all kinds of technical tools. I mean if you think about it, this is just past the exploration phase into the delineation phase. So the fact is, you have to put a lot of extra cost in. We need to get our well costs down to $12 to $14 million; we have in our models a pathway to get there. Neither of these wells were setup to be development wells. So, again the extra cost of ceramic proppant or down-hole tools or extensive testing, pilot holes, all of that sits with these.

I guess the next step for us is to learn enough about what we have across the field where we have it. We've got significant resource that we believe is present, across significant acreage that we believe is present. And then begin to move into when we get enough of an understanding of the model, some additional 3D and others, then begin to think about okay what's the cycle look like for timing to begin drilling development wells. So there's the risk profile for Utica, there's the learning; there's all that. Then you go and they get to play the same strategic, rigorous capital allocation process like all the Marcellus wells do. You put them in the matrix and you see based on gas prices, based off of differentials, based off of volumes and capital costs, etc., where do they stack up in the portfolio.

Certainly, the first well looks incredibly encouraging. We have a second and there are some additional wells going forward. But these wells today are $20 million wells in the test phase. We want to use a measured approach along with capitalizing on the terrific acreage we have all around in the liquid side and the gas side. We have a gathering solution for a portion of our acreage, which we're excited about; we've had it for some time. That has to be built. And then you figure out where along the system do you need to put additional gathering and what's the timing of that. And those commitments get made when you get more confident around the development.

Operator
Our next question is from the line of Holly Stewart with Scotia Howard Weil. Please proceed with your questions.

Q: Maybe just following up quickly on Doug's question with the Utica. Just maybe thought process around testing Washington County and then how many acres do you have there?

Bill Way - President & Chief Executive Officer
In terms of why we tested Washington County?

Q: Yes.

Bill Way - President & Chief Executive Officer

I think you're going to find that we're going to test across different places in the portfolio. Washington County, there's a gathering line near where that well was drilled, which enables us to do more than a flow test to actually bring it online and are able to do that. So watch us, look around as we do the areal extent of our acreage, try to figure the different subsurface characteristics or different gathering availability, that kind of thing, that drives some of those decisions. And so, you don't want to put them all in place. If you do then you end up proving up or delineating a smaller footprint. So, you'll us spread out, then we'll leverage the data that we have surrounding us as well. So there's a bit of an impact on that in that decision matrix.

Q: And then maybe just one final one on the transportation. You have big ramp expected in the Northeast or in Appalachia in the second half of the year. Just trying to balance out how to think about that how your transportation cost will look as these projects get turned into service?

Michael Hancock - Vice President of Investor Relations
This is Michael. On the Northeast side, obviously, the stuff we added will bring down the cost a little bit. So, you're still in that $0.30 plus or minus range. So it's still very attractive there. In Southwest Appalachia, it does increase on the cost side but it's probably a $0.10 type number today going into about $0.50 longer term and that's offset by the much improved realizations down at the Gulf Coast and [indiscernible] down there, so net-net a good story.

Bill Way - President & Chief Executive Officer
And just to supplement that a little bit from a strategic level, you will notice obviously that, we discussed it earlier on the call, our implementation of our strategy to lock up the full volume growth of potential firm in Northeast is different than what we're doing in Southwest Appalachia. First of all, there's a lot more pipeline capacity that we've built in Southwest, the area and the market that locally and where these pipelines go serve us much more liquid.

The cost of these pipeline projects are dramatically higher than, and with much longer terms, than we had and historically seen in our asset. So we put in—we committed to about 800 million a day of firm capacity in a number of projects out of Southwest Appalachia, knowing that we would need much more, but also knowing and believing the sort of industry belief that as we move through time those costs to transport, those differentials, the cost of expansion capacity, all of that brings those costs down and we'll leg into it again, as we need it going forward for the long-term.

Operator
Our next question is from the line of Bob Morris with Citi. Please proceed with your questions.

Q: Just one quick follow-up question on the Moorefield, the average cost for the two wells in the quarter was $4.3 million above the $3.8 million average for the seven wells in the first quarter. In Q2, was that average skewed up by the one well that encountered the fault? And then secondarily, how much experimentation or science are you doing here such that once, and if you do go into development mode, what should we think about the development mode well cost being, I think, play out here in the Moorefield?

Jack Bergeron - SVP of Operations
Okay. This is Jack. On these two wells, both of them, but the one specifically the one we quoted cost on, we did a lot more logging on it, science and we tried some different completion intensity that drove the costs up. Realistically, it's probably somewhere between the two but skewed more towards the development cost. The $3.8 million was a little development pad and so that's a lot more indicative of what development costs would be, instead of one-off well with a full mode.

Q: Okay, great. I mean if you're $3.8 million with 5 or 6, 7 Bcf those are pretty good economics, so hopefully that continues to play out. Thank you.

Operator
Our next question comes from the line of Jason Gilbert with Goldman Sachs. Please proceed with your questions.

Q: Hi. Thanks for taking my questions. Jennifer in your prepared remarks, you mentioned the company continues to look at ways to opportunistically de-lever, de-lever I think was one of the words you used. I was wondering if you could maybe elaborate on that a little bit.

Jennifer Stewart - Chief Financial Officer
Well, what we would look to, our first priority would be to address our $327 million unsecured term loan, as we run into excess cash flow or we come into some sources that we can pay that down. We may also look to address the 2020 notes. If we can have an opportunity to take to address those notes, we're going to consider it. But our credit agreement looks to that $327 million unsecured term loan first to pay that down and then we look to address the 2020 to try to push that maturity stack out.

Bill Way - President & Chief Executive Officer
And as part of our overall way we run our business is we look at these sort of longer dated—2020 is several years away but in banking terms it's very short. So we do this and every other one of these efforts to improve our position by looking out far enough and proactively managing it so we retain all the options we can and then execute on it and let you know when we're done.

Q: And maybe your non-core asset sales, maybe part of the plan here?

Bill Way - President & Chief Executive Officer
Well, we've sold off in the past some acreage that was very long dated. We have our three large scale assets. We have very little sort of non-core assets. Most of them are in the exploration zone. Those we continue to look at, but to-date we haven't had any movement on those.

Q: And one more follow-up and I don't know if it's a totally fair question, but let's fast forward a year from now. You got a lot of going on with your various assets. You got debottlenecking occurring in Northeast Appalachia. You got the new Utica wells. You're working hard to improve the economics in the Fayetteville. You got the Moorefield. A year from now, I mean you just said I think that the Northeast Appalachia was the top rung of the ladder currently, but how would you—if everything goes as planned, how do you think the economics rank between the various areas on the 2Q 2018 call?

Bill Way - President & Chief Executive Officer
I like everything goes exactly like your plan, then all three of them are highly economic and they compete at a much higher level. What I will tell you is that where we sit today with the opportunities and things that we've captured, our two Northeast assets, large scale as they are, compete back and forth and the liquid side of that business, the realizations from NGLs, which is such as substantial portion of the very rich gas we have in West Virginia, is really the lever that moves that decision back and forth.

We've become so efficient that we can capture both opportunities for both areas with five rigs and less. I mean it's a very—the capital efficiency is so high, because we own them of course, we can just move them from place to place and we do that on a flexibility basis. If you want to look at that in bulk, our Northeast assets today have the highest. In a year from now, I am not going to predict all the great things or outcomes that our Fayetteville team will do because they will always impress. And so there's the opportunity for them to jump in there. But as we look right now with what we know right now, that's where the priority is or the majority of the development type capital would go.

Operator
Our next question is from the line of Sean Sneeden with Guggenheim. Please proceed with your questions.

Q: Maybe just to follow-up on the Jason's question there, but Jennifer, when you think about the capital structure, do you envision a scenario where you're able to extend the term loan and actually return to more of an unsecured capital structure or fully unsecured capital structure? Or is the intent to keep the current complex relatively similar and just extend the maturities?

Jennifer Stewart - Chief Financial Officer

Our objective is to simplify our capital structure. Given that we're currently with all the rating agencies we're in the high yield world, we certainly would like to get back to investment grade and have an unsecured capital structure, that's a certainly our long-term objective. Right now, we're looking to simplify the current capital structure, make it a little more easier for you all to understand and for everyone to understand, and we're opportunistically looking to do that as we get a tailwind in the credit capital markets.

Q: Okay, that's helpful. Then just one housekeeping question, but when we think about as you guys exit this year, how should we think about the overall maintenance capital kind of keep you flat at that run rate?

Jennifer Stewart - Chief Financial Officer
We're estimating about $900 million.

Q: I'm sorry $900 million.

Jennifer Stewart - Chief Financial Officer
We are estimating about $900 million to hold flat exit to exit in 2018.

Operator
Our next question comes from the line of Daniel Norman with Wells Fargo. Please proceed with your questions.

Q: Hi, it's Dave Tameron from Wells. And actually to be honest, everything has been answered so I'd just say a welcome to Jennifer and David Cecil on the new hires. So, that's all I got. Thanks.

Jennifer Stewart - Chief Financial Officer
Thank you.

Operator
Thank you. At this time, I'll turn the floor back to Bill Way for closing remarks.

Bill Way - President & Chief Executive Officer
Well, I hope you've heard in our discussion here, we're very proud of the continuing accomplishments of our teams across the company, and how the company is positioned to capture the full potential of our large scale assets. We've accomplished a great deal in a short amount of time, and we're driving forward with further innovation and focus to extract even more value from these assets.

With our differentiating technical, operating capabilities to improve well productivity and our relentless focus, as I hope you've heard, on improving capital efficiency driving margin expansion, the existing inventory is building quite a bit of potential and our delineation efforts and our impressive marketing transportation capabilities are all underpinned by our rigorous financial discipline and stringent capital allocation practices. We think there are multiple, exciting catalysts on the horizon and we're ready to ignite those further.

We look forward to joining with you guys next quarter and talk a bit more about all the achievements that we have and we want to thank you for joining us today, and wish you a good weekend.